Direct Testimony and Schedules
Ian R. Benson

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-20-723
Exhibit___(IRB-1)

Transmission

November 2, 2020

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ian Benson. I am the Area Vice President for Transmission Strategy and Planning for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company – Minnesota (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 29 years of experience in the utility industry and have served in positions in nuclear generation, retail electric marketing, wholesale power purchases and sales, and transmission. In my current position as the Area Vice President for Transmission Strategy and Planning, my responsibilities include supervising department engineers in planning electric transmission system expansions, recommending specific construction projects to Xcel Energy management and the Midcontinent Independent System Operator, Inc. (MISO), overseeing transmission-related agreements with MISO and other counterparties, and resolving wholesale customer transmission service concerns. My resume is attached as Exhibit___(IRB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present and support the Company's capital forecasts and operation and maintenance (O&M) expense requests for the Transmission organization for purposes of determining electric revenue requirements and final rates in this proceeding. I also provide information related to third-party transmission expenses and wholesale transmission revenues and their impact on the Company's revenue requirements. Further, I discuss a pending Federal Energy

Regulatory Commission (FERC) complaint against the MISO transmission owners related to the return on equity (ROE) and its potential impact on our third-party transmission expenses and wholesale revenues. Finally, I report on methods for calculating transmission system line losses as required by the Commission's order in the Company's 2015 electric rate case (Docket No. E002/GR-15-826).

Q. WHAT ARE THE KEY RESPONSIBILITIES AND OBJECTIVES OF THE TRANSMISSION ORGANIZATION?

A. The NSP Companies, NSPM and Northern States Power Company – Wisconsin (NSPW), own, operate, and maintain an integrated transmission system that has facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin, and the upper peninsula of Michigan (NSP Transmission System).

The Transmission organization is responsible for the planning, construction, operation, and maintenance of these transmission facilities that allow energy to be safely and reliably transported from generating resources (both Company-owned and third-party owned) to the distribution systems that serve customers. The Transmission organization is focused on ensuring that the NSP Transmission System is reliable, resilient, and able to efficiently accommodate an increasingly diverse and dispersed number of generators.

Q. WHAT WORK DOES THE TRANSMISSION ORGANIZATION UNDERTAKE TO ENSURE RELIABILITY OF THE TRANSMISSION GRID?

A. The Transmission organization makes investments that maintain and improve the reliability of the transmission system. An important component of maintaining the reliability of the transmission system is replacing or refurbishing facilities that are in poor condition or have reached the end of their life. Many of our transmission facilities were placed in-service more than 50 years ago and, in some cases, these facilities are 70 years old or older. For instance, on the NSP Transmission System, we have more than 500 miles of line that is 70 years old or older. The Company continually assesses the age and condition of transmission facilities. While age is not dispositive of the condition of an asset, it is often used to identify assets for which condition may be a concern. Likewise, while it is not necessarily the case that every asset should be replaced at the end of its service life, in some cases, the age of the Company's facilities increases the likelihood that an element will fail when stressed.

Additionally, recent severe weather incidents, including the derecho storm that hit parts of the Midwest on August 10, 2020 and the California wildfires, have underscored the importance of addressing the condition of aging transmission infrastructure. The Transmission organization has several programs, including its Major Line Rebuild program, that are focused on examining and evaluating the condition and performance of each component of the transmission system. We then prioritize new investments based on this evaluation and make the necessary repairs and upgrades to maintain the reliability of the system.

Q. ARE THERE OTHER FACTORS AND INVESTMENTS THAT IMPACT TRANSMISSION SYSTEM RELIABILITY?

A. Yes. Another part of maintaining the reliability of the system involves making investments to maintain compliance with the mandatory standards set by the North American Electric Reliability Corporation (NERC) and FERC. We are constantly studying our system to determine what additional infrastructure investments are needed as these standards are updated and as customer loads and generation mixes change.

Further, the reliability of our transmission system also depends on the physical security and resiliency of the system. Thus, in addition to reliability standards, NERC has also issued physical security standards, or Critical Infrastructure Protection (CIP) standards, to protect the transmission system's key physical assets from potential threats and attacks. Transmission also makes investments to improve the physical security of our substations to comply with these CIP standards. These investments include improving the perimeter fencing, installing additional cameras and other monitoring devices, and replacing substation gates.

Q. WHAT WORK DOES THE TRANSMISSION ORGANIZATION UNDERTAKE TO SUPPORT INCREASINGLY DIVERSE AND DISPERSED GENERATION RESOURCES?

A. The Transmission organization makes investments to reliably and cost-effectively accommodate new generation. In recent years, we have witnessed unprecedented amounts of renewable energy seeking to interconnect to the grid. As of September 1, 2020, there was 107.6 gigawatts of new capacity in the MISO queue associated with 717 individual projects, the vast majority of which were new wind and solar projects. To accommodate some of these new generators, who are seeking to interconnect their projects with the Company's transmission system, the Company will be making increasing investments to facilitate their interconnection over the course of the multi-year rate plan.

Concurrent with this growth in renewable generation, Xcel Energy and other utilities are in the process of retiring large fossil fuel generation plants. This shifting generation mix has required, and will continue to require, more than just individual interconnection projects. This shift will require large regional expansion investments similar to the CapX2020 projects and the MISO's Multi-Value Projects (MVPs) to integrate the large quantities of low-cost renewable energy currently pending in the MISO queue.

Q. HOW WILL THE COMPANY IDENTIFY NEW TRANSMISSION PROJECTS THAT WILL BE REQUIRED TO ACCOMMODATE NEW GENERATION?

A. To develop this next set of transmission projects, Xcel Energy, along with its other CapX2020 partners, published the CapX2050 Transmission Vision Report (Vision Report) in March 2020.[1] The purpose of this report was to provide stakeholders with a basic understanding of the potential operational and planning issues that need to be considered and addressed to facilitate the transition from traditional dispatchable generation resources (coal, natural gas, and nuclear) to a fleet with more non-dispatchable, weather-dependent resources (wind and solar). This Vision Report will lay the foundation for future studies by the CapX2050 partners and MISO that will result in a long-term transmission plan to facilitate greater reliance on renewable, non-dispatchable resources. While we do not plan to in-service any new regional expansion projects during the term of this multi-year rate plan, this Vision Report, along with MISO's annual transmission report, will help guide our future transmission investments in this area.

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[1] A copy of this report is publicly available at:
http://www.capx2020.com/documents/CapX2050_TransmissionVisionReport_FINAL.pdf

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In my Direct Testimony, I will discuss the Transmission organization and the NSP Transmission System. I will also describe the various entities, in addition to the Minnesota Public Utilities Commission (Commission), that regulate the transmission system.

I will explain that the Transmission organization is proposing capital additions of approximately $354.0 million for 2021, $340.0 million for 2022, and $316.7 million for 2023 to support the objectives I discussed above. These capital additions include the Huntley–Wilmarth 345 kV Project for which the Company will continue to seek recovery of through the Transmission Cost Recovery (TCR) Rider. The Huntley–Wilmarth 345 kV Project has capital additions of $73.2 million in 2021 and $4.3 million in 2022. Company witness Mr. Benjamin C. Halama will discuss the TCR Rider cost recovery in greater detail. I will describe Transmission's six capital budget groupings and the importance of these investments in maintaining a safe, reliable, and robust transmission system. I will provide details about the major planned investments and key capital projects that the Transmission organization will place in service during the term of this multi-year rate plan.

I will also discuss the Transmission O&M budgets for 2021 to 2023, which are driven by internal labor, contract labor and consulting, fees, and materials. The Transmission O&M budget for 2021 is $38.2 million, $38.7 million in 2022, and $40.4 million in 2023. The average O&M expense budgeted for these three years ($39.1 million) is below the most recent three-year historical average (2017 to 2019) of $39.20 million. I will provide further explanation as to why our

O&M budget for each year is reasonable and allows us the ability to perform the work necessary to construct and maintain the transmission system.

Additionally, I will discuss the MISO third-party transmission expenses and wholesale transmission revenues that are budgeted for 2021 to 2023. The third-party transmission expense for 2021 is $93.2 million, 2022 is $96.2 million, and 2023 is $98.0 million. These costs are the result of the NSP Companies serving their native load customers in five other MISO pricing zones and a small load outside of MISO. The wholesale transmission revenues are $92.8 million for 2021, $97.4 million for 2022, and $99.9 million for 2023. This revenue is the result of transmission services and ancillary services provided to other utilities with load in pricing zones where NSP owns transmission assets.

Finally, I report on methods to calculate line losses on the transmission system as required by the Commission's Order in the Company's 2015 electric rate case.

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- *Section II* – Transmission System Business Unit
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – Third-Party Transmission Expenses and Wholesale Transmission Revenues
- *Section VI* – Transmission System Line Loss Analysis

II. TRANSMISSION SYSTEM BUSINESS UNIT

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S TRANSMISSION SYSTEM.

A. The NSP Companies (NSPM and NSPW) are vertically integrated electric utilities that own and operate electric transmission facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin, and the upper peninsula of Michigan. Together, the NSP Companies own an integrated transmission system comprising approximately 8,400 miles of transmission facilities operating at voltages between 34.5 kV and 500 kV, and approximately 548 transmission and distribution substations. The NSP Companies are transmission owning members of MISO. The NSP Transmission System is planned and operated on an integrated basis and has been under the functional control of MISO since it began operations in February 2002. Transmission service over the NSP Transmission System is open access, and transmission service reservations can be requested and approved under the terms of the MISO Tariff.

Q. CAN YOU DESCRIBE THE CUSTOMERS SERVED BY THE NSP TRANSMISSION SYSTEM?

A. The NSP Transmission System serves the following two customer groups: (1) retail native loads in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan; and (2) the loads of other investor-owned utilities, cooperatives, and municipal load serving entities (LSEs), and wholesale customers. The wholesale customers comprise approximately 20 percent of the total demand on the NSP Transmission System, with the remaining demand composed of retail native load customers. From a transmission planning and transmission service perspective, our retail customers and the wholesale customers require the same level of service, and as a result, the system is planned to serve the needs of each type of customer equally.

Q. OTHER THAN STATE REGULATORY COMMISSIONS, SUCH AS THE MINNESOTA PUBLIC UTILITIES COMMISSION, WHAT OTHER ENTITIES REGULATE THE NSP TRANSMISSION SYSTEM?

A. The NSP Transmission System is regulated primarily by three entities other than state regulatory commissions. The first is FERC. FERC is a federal independent agency that regulates the interstate transmission of electricity, natural gas, and oil. The Energy Policy Act of 2005 gave FERC additional responsibilities. As part of that responsibility related to electric transmission, FERC:

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
- Reviews the siting applications for electric transmission projects under limited circumstances;
- Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- Enforces FERC regulatory requirements through imposition of civil penalties and other means; and
- Administers accounting and financial reporting regulations and conduct of regulated companies.

The second is NERC. NERC is a not-for-profit international regulatory authority whose primary role is to assure the reliability and security of the country's Bulk Electric System (BES). NERC does this by issuing and enforcing reliability standards, which transmission operators, including the Company, are required to comply with; annually assessing seasonal and long-term reliability; monitoring the BES through system awareness; and educating, training, and certifying industry personnel. As the certified Electric Reliability Organization (ERO), NERC is subject to oversight by FERC.

Third is the Midwest Reliability Organization (MRO). MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north-central region of North America, including parts of both the United States and Canada. MRO is one of six regional entities in North America operating under authority from regulators in the United States through a delegation agreement with NERC, and in Canada through arrangements with provincial regulators. The primary purpose of MRO is to ensure compliance with reliability standards and perform regional assessments of the grid's ability to meet the demands for electricity. MRO audits the NSP Companies for compliance with NERC's reliability standards.

Q. PLEASE DESCRIBE MISO AND ITS ROLE WITH RESPECT TO THE NSP TRANSMISSION SYSTEM.

A. MISO is an independent system operator and regional transmission organization providing open-access transmission service, monitoring the high-voltage transmission system, and operating one of the world's largest real-time energy markets. NSPM and NSPW are transmission-owning members of MISO. This means that, although the NSP Companies own and maintain their transmission assets, MISO operates the NSP Transmission System, in conjunction with the transmission systems of the other 52 transmission owners. Furthermore, MISO establishes: (1) the process and rules for wholesale customers to access the NSP Transmission System on a non-discriminatory basis; (2) the annual transmission planning process for expanding or upgrading the regional transmission system, which includes the NSP Transmission System (i.e., MISO Transmission Expansion Plan (MTEP)); and (3) the policies and procedures that provide for the allocation of costs incurred to construct certain transmission upgrades and the distribution of revenues associated with those costs.

Q. PLEASE DESCRIBE THE DEPARTMENTS WITHIN THE TRANSMISSION ORGANIZATION AND THEIR KEY FUNCTIONS.

A. There are six departments within the Transmission organization. The key functions of these departments are as follows:

- *Asset management* is responsible for substation field engineering, which includes routine and emergency maintenance and operational activities for all Xcel Energy substations. The organization also provides field implementation of certain NERC and CIP compliance activities, and "commissioning" new substation facilities. Commissioning of Xcel Energy substation facilities involves ensuring that our substation facilities meet the operational and reliability requirements of FERC and NERC as well as Xcel Energy. The Quality Assurance/Quality Control (QA/QC) process performed by Xcel Energy commissioning engineers and technicians thoroughly tests the equipment and control systems of our electric substations prior to energizing. This organization is also responsible for system sustainability. System sustainability provides, among other things, electric material and design standards for the design, construction, and maintenance of our transmission assets by interpreting industry standards such as the American National Standards Institute (ANSI). System sustainability is also responsible for developing Xcel

Energy's reliability-centered maintenance programs that ensure the health and reliability of existing assets. These processes establish the baseline performance expected by our operations and maintenance organizations and confirm the performance for compliance standards.

- *Transmission strategy and planning* is responsible for: (1) life cycle planning, transmission system planning, and associated capital budgeting; (2) negotiating transmission-service-related contracts with generators, transmission owners, and distribution utilities; and (3) resolving wholesale customer transmissions service concerns. In addition, this organization manages Xcel Energy's participation in key regional projects throughout its service territory, as well as other regional projects on and adjacent to Xcel Energy's transmission systems, including the NSP Transmission System. This group is also responsible for Xcel Energy's policies and procedures in the competitive transmission acquisition processes pursuant to various requirements of FERC Order 1000. I serve as the Area Vice President for this organizational area.
- *Field operations* provides field services for construction, maintenance, and emergency repairs for transmission assets.
- *Transmission portfolio delivery* is responsible for managing capital projects, programs, and portfolios, including designing and engineering transmission assets, managing third-party contractors, and securing and managing transmission land rights.
- *System operations* is primarily responsible for the NERC Balancing Authority and Transmission Operations function for all Xcel Energy transmission systems, including the NSP Transmission System.

- *Transmission business operations* directs the Transmission business unit's efforts pertaining to compliance with NERC requirements and directs business performance achievement efforts.

III. CAPITAL INVESTMENTS

A. Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss capital budget trends for Transmission from 2017 to 2020 and discuss major planned investments and key capital projects for 2021, 2022, and 2023. I will also provide details regarding how the Transmission business unit develops its annual capital budget and correspondingly identifies and prioritizes capital projects within the confines of the capital budget. Furthermore, I will discuss how Transmission monitors and controls spending on capital projects as they move from approval through construction.

Q. PLEASE MAKE THE OVERALL BUSINESS CASE FOR TRANSMISSION'S CAPITAL PROGRAM.

A. Reliable and efficient electric service for our customers depends on a strong transmission system composed of facilities that are in good working order and that are able accommodate a diverse mix of generators. The capital investments made by the Transmission business unit are necessary to allow the electricity generated by Company-owned and third-party generators to reach our customers. To maintain the health and reliability of the transmission system, the Transmission organization has made and continues to make reasonable investments in maintaining existing facilities and building new transmission infrastructure to replace facilities in poor condition or to meet NERC requirements or to accommodate new generators. These investments ensure the reliable electric service that residential customers and businesses expect, while also supporting a competitive wholesale electricity market that allows access to low-cost generation across the MISO system.

Absent ongoing investments in our transmission system, the reliability and efficiency of this important system would be at risk. The Transmission organization recognizes that the Company's overall budget is limited, and we seek to prioritize projects in a manner that achieves an appropriate balance in maintaining the health and reliability of our transmission system while also making long-term, cost-effective investments for our customers.

Q. GENERALLY SPEAKING, WHAT TYPE OF CAPITAL INVESTMENTS ARE MADE BY THE TRANSMISSION ORGANIZATION?

A. Our capital projects require investments in transmission line components, such as poles, conductors, gang-operated switches, and land rights for transmission line easements. They also include investments in substation components such as transformers, capacitor banks, reactors, circuit breakers, relay and communication equipment, remote terminals, and real property.

Our capital projects fall into two main categories. The first consists of large capital projects that are often multi-year projects. These projects are capital intensive and are aimed at improving the transmission system; upgrading existing facilities to meet NERC compliance requirements and to accommodate new generation; replacing aging facilities; and making improvements to communication infrastructure and physical security.

In addition to these larger capital projects, Transmission also completes many smaller capital projects each year. These smaller projects comprise a majority of the total number of projects that we complete each year, but make up only a minor part of our overall capital budget. Some examples of these smaller projects include replacement of one to two structures or cross-arms due to condition, storm damage, or age. Figure 1 and Figure 2 below depict this breakdown for 2021-2023 for NSPM and NSPW. As shown in these figures, our capital projects with greater than $10.0 million each in capital additions make up 83 percent of our total capital additions budget each year for NSPM and NSPW, but comprise only 24 percent of our total number of projects.

Figure 1

2021-2023 Total Number of Transmission Capital Projects

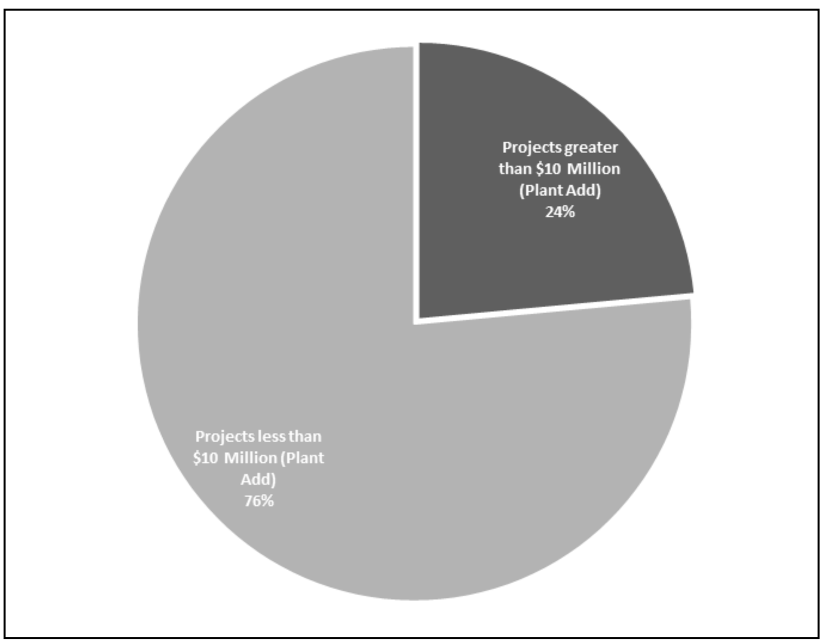
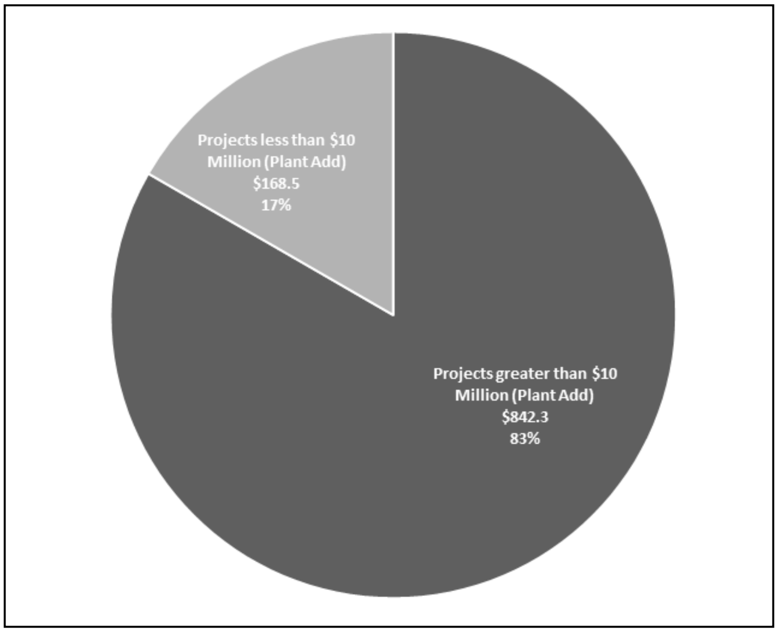


Figure 2

2021-2023 Total Transmission Capital Budget

(Dollars in Millions)



Q. ARE THERE ANY OTHER UNIQUE FEATURES OF TRANSMISSION'S CAPITAL INVESTMENTS?

A. Yes. Transmission's capital projects often require several years of development and construction before they are placed in-service as capital additions. This is because many of our capital projects require multiple steps, such as transmission study work and planning, route selection, initial design, permitting, final design, land acquisition, site preparation, and then construction. As a result, the Company may have capital expenditures for a particular project that span multiple years, with an in-service date several years after the first expenses are incurred.

Q. HOW DOES TRANSMISSION CATEGORIZE ITS CAPITAL ADDITIONS?

A. Our capital projects fall into six capital budget groupings based on the main purpose of the project. These grouping are:

- Asset Renewal: This category is primarily for managing the health and performance of transmission assets. The main goal is to ensure that critical assets including transmission lines, substations, and other related assets meet reliability and capacity requirements, while minimizing life-cycle costs. This includes planned replacement of aging transmission lines and substation equipment; unplanned replacement of lines or equipment damaged by storms; additions to, or replacement of, aging fleet vehicles and tools that support capital additions; and line relocations due to road projects.
- Reliability Requirement: Reliability projects are constructed to ensure that the transmission system is complaint with all NERC reliability standards. Compliance with NERC reliability standards is mandatory for all users, owners, and operators of the BES. FERC, NERC, and regional reliability entities monitor and enforce compliance. Any entity found non-compliant may be subject to fines of up to $1.2 million per day per violation. The Transmission organization is continually studying the transmission system to assess compliance with NERC standards. These studies analyze the impacts of forecasted load growth, existing and anticipated generation needs, and new generation interconnections to determine whether transmission upgrades are necessary.
- Interconnection: This category includes projects that the Company is required to construct under the FERC Open Access Transmission Tariff (OATT) to accommodate interconnection requests from generators, transmission lines, and new load.

- Physical Security and Resiliency: There are two critical aspects to this grouping of projects: physical security and grid resiliency. Physical security addresses physical threats to utility infrastructure, such as transmission lines and substation equipment. Grid resiliency addresses the Company's ability to monitor and recover from incidents occurring on our system to limit disturbances that may leave our service territory exposed to prolonged outages, oftentimes by adding redundancy to our transmission system. This category also includes projects intended to address NERC standards related to security and grid resiliency.
- Regional Expansion: This category includes major high voltage transmission line projects that are developed through the regional planning process and serve multiple needs including regional and local reliability and renewable energy outlet. Generally, these are multi-year initiatives and the types of projects for which the Company seeks a Certificate of Need and/or Route Permit from the Commission. This category also includes projects necessary to support economic development.
- Communication Infrastructure: This category includes the fiber optic and communication network infrastructure build-out on the existing transmission system to improve communication connectivity for all business units. This infrastructure allows the digital transfer of Supervisory Control and Data Acquisition (SCADA) data and teleprotection services. As telecommunication service providers are retiring the existing obsolete analog connections, Xcel Energy will be continuing our efforts to privatize our communication network infrastructure across the NSPM and NSPW service territories. By reducing dependencies on third-party telecommunications and building

our own, the transmission system communication infrastructure improves the transmission and distribution system reliability, performance, and cyber security.

Many of our capital additions serve multiple purposes, but for budgeting purposes, we classify the capital project according to its primary purpose.

B. Transmission Capital Budget Development and Management

Q. HOW DOES TRANSMISSION ESTABLISH A REASONABLE CAPITAL BUDGET FOR A GIVEN YEAR?

A. The annual capital budget for Transmission is based on collaboration between corporate management of the overall Company finances and the business needs that are identified by Transmission. Company witness Ms. Melissa L. Ostrom explains how the Company establishes overall business unit capital spending guidelines and budgets based on financing availability, specific needs of business units, and the overall needs of the Company.

Q. CAN YOU PROVIDE A SUMMARY OF TRANSMISSION'S CAPITAL BUDGETING PROCESS?

A. Transmission employs a "bottom-up" budgeting process to identify the capital projects that we need to complete within a specific year for our business unit. All of our capital projects are executed under our Capital Project Governance Process. This governance process has policies and procedures in place that enable Transmission to prioritize and balance our budget such that we appropriately allocate funds. Our capital budgeting process includes four main steps:

1. Identification of potential projects,

2. Vetting of potential projects,
3. Prioritization of potential projects, and
4. Rebalancing and reprioritization of projects based on corporate budget requirements.

Q. WHAT IS THE FIRST STEP IN YOUR BUDGETING PROCESS?

A. We begin our budgeting process by identifying and assessing the potential work that is proposed for integration into the current five-year budget period. New projects must satisfy a clearly defined purpose and need. The criteria used to identify and assess projects are based on the six capital budget groupings I discussed earlier. The budgeting process also takes into account existing projects that were previously approved based on the corporate governance approval requirements that Ms. Ostrom describes. The annual budget is a very dynamic process where new project needs and financial requirements are prioritized against existing projects that most often take multiple years from initial budget approval to construction completion and close out.

Q. HOW DO YOU IDENTIFY ASSET RENEWAL PROJECTS?

A. Our system sustainability group identifies facilities in need of replacement or refurbishment based on a variety of factors. For transmission lines, these factors include: (1) the importance of a particular line to being able to reliably serve customers; (2) the line's age and condition; and (3) the line's reliability history. These factors receive different weights to determine which lines are in the greatest need of replacement. Generally speaking, those lines that will negatively affect the most customers if they fail are placed higher on the list for replacement. For substation assets, a similar matrix is used. The system sustainability group then uses these lists to determine the urgency of each replacement and identifies specific projects for possible inclusion in the budget.

Asset Renewal projects also include relocations required by road construction projects. We work with federal, state, and local highway road departments to identify needed relocations.

Q. HOW ARE RELIABILITY REQUIREMENT PROJECTS IDENTIFIED?

A. Our Reliability Requirement projects are identified based on MISO's annual MTEP studies, which are an RTO lead reliability study effort. NERC requires utilities to perform annual assessments of their transmission system. The Company performs this annual assessment by participating in the MISO MTEP process. The MISO MTEP studies the performance of the system using 1-year, 5-year, and 10-year future models. MISO typically finalizes its annual MTEP study in December of each year.

Q. HOW DO YOU DEVELOP AN INITIAL LIST OF INTERCONNECTION PROJECTS FOR THE BUDGETING PROCESS?

A. Our Transmission planning department gathers all available information from interconnection requests submitted to the Company, either internally, from other utilities, or from MISO, who administers generation interconnections.

Q. DO YOU DEVELOP A BUDGET TO ACCOUNT FOR PREVIOUSLY UNIDENTIFIED INTERCONNECTION REQUESTS?

A. Yes. The Company typically receives interconnection requests year-round, some of which will require specific funding in years that were not previously planned for in our typical budget cycle. For the projects not accounted for in our typical budget cycle, the Company holds funding in a program called Interconnection Agreement (IA) Tariff Fund. The amount budgeted for this program is based on historical averages and known demand of Interconnection project requests. As the Company receives these previously unplanned requests, funding is made available from the IA Tariff Fund to a specific interconnection project as appropriate.

Q. HOW ARE PHYSICAL SECURITY AND RESILIENCY PROJECTS IDENTIFIED?

A. Physical security projects are identified based on the NERC CIP-014-2 standard. In 2018, the Company performed a vulnerability analysis of our BES (100 kV and above) substations within the NSP System. The analysis identified critical facilities and physical security improvements at multiple BES substations throughout the NSP system and was validated by third-party review as is required by the NERC standard. After validation, each identified site is prioritized for possible inclusion in the budget. CIP-014-2 requires that the Company reevaluate our system every two years, so we anticipate that this biennial study will continue to identify these capital projects as our transmission system evolves.

Grid resiliency projects address the Company's ability to monitor and recover from incidents occurring on our system to limit disturbances that may leave our service territory exposed to prolonged outages. For example, based on FERC Order 754, non-redundant equipment required to facilitate breaker operation was added, as a contingency event, to the NERC TPL-001-4 standard. System planning identifies projects annually as part of their TPL-001-4 study to remediate reliability impacts caused by contingencies for possible inclusion into the Transmission budget.

Q. HOW ARE REGIONAL EXPANSION PROJECTS IDENTIFIED?

A. As I mentioned earlier, the Company takes part in regional transmission planning efforts to identify needed Regional Expansion projects. The Company is involved with the CapX2020 initiative, which identified and constructed the CapX2020 group of projects. As I also mentioned above, this same group of utilities recently completed the CapX2050 Transmission Vision Report to understand the potential operational and planning issues associated with the transition to more renewable, non-dispatchable generation resources.

The Company also takes part in MISO's yearly MTEP process, which works with all MISO transmission owners and stakeholders to identify Regional Expansion projects. The MTEP process identifies regional system needs and develops and vets possible solutions. The solutions that best meet the long-term needs of the regional transmission system are then approved by the MISO Board of Directors in the annual MTEP process.

Q. HOW ARE COMMUNICATION INFRASTRUCTURE PROJECTS FIRST IDENTIFIED?

A. Our substation communication engineering group identifies and assesses projects based on a specific set of criteria that considers issues like BES criticality, past performance of systems currently in-service, O&M costs associated with existing leased connections, telecommunication companies phasing out certain technology, benefit to other business units, and integration into existing Company-owned infrastructure. Based on this analysis, the substation communication engineering group identifies projects for consideration in the Transmission capital budget.

Q. AFTER THE LIST OF POSSIBLE CAPITAL PROJECTS IS DEVELOPED, WHAT IS THE NEXT STEP IN THE BUDGETING PROCESS?

A. The project originator develops a proposed statement of work for each project, normally consisting of the proposed preliminary scope, project description, need and benefits description, alternatives and proposed option, desired completion date, consequences of not doing the project, and a basic electric circuit diagram.

Multi-disciplinary project teams are then assembled. These project teams have a diverse set of functional skills including financial management, project management, design and engineering, system operations, construction, siting and land rights, scheduling, vegetation management, and planning. The project teams develop a detailed preliminary scope and schedule for the project with supporting documentation. The project team may also prepare high-level cost estimates to assess alternatives and weigh proposed solutions against other alternatives. These estimates help determine the most reasonable electrical and financial solution to meet the identified transmission needs. The preliminary project scope for the preferred solution is entered into Transmission's budgeting and forecast software tool, called TamCasting.

Q. WHAT HAPPENS AFTER THE PRELIMINARY SCOPE IS DEVELOPED?

A. The proposed project is presented for preliminary scope approval at the regular occurring Constructability (C1) meeting. All projects must pass through this C1 gate before proceeding to the next project phase. At this C1 meeting, the project's preliminary scope is peer reviewed by employees from relevant functional areas of the Transmission organization (including project management, engineering design, Transmission planning, siting and land rights, construction, and operations). The objective of this meeting is to review and challenge the project need and the proposed preliminary scope while looking for fatal flaws or better solutions. Project alternatives are reviewed to determine whether the proposed solution is the most cost-effective and provides the most long-term value for our customers.

Approval at the C1 meeting allows the project to pass through the C1 gate to the next step in the process. Projects not approved at the C1 meeting are either cancelled or returned to the project origination phase for further need and preliminary scope development based on peer review feedback at the C1 meeting. The project may be re-presented at a future C1 meeting for approval.

Q. IF A PROJECT IS APPROVED AT A C1 MEETING, WHAT IS THE NEXT STEP?

A. The project proceeds to the budget estimate package phase. Based on the C1 approved preliminary scope, the project manager coordinates the development of a budget estimate by reviewing the project deliverables with the project team, identifying and documenting routing and design assumptions, conducting field visits, and collecting estimates generated by engineering, siting and land rights, construction, and vegetation management. In special circumstances, pre-construction work orders are generated for planning and development costs—such orders require immediate, out-of-cycle budget approval. The project group also begins to develop an outage plan, a project-specific safety plan and site security plan, and prepares a preliminary risk register. The project team then assembles the budget estimate package and presents it for approval as part of the annual budget process. This is referred to as the "Budget Approval" phase.

Q. WHAT ACTIVITIES TAKE PLACE IN THE BUDGET APPROVAL PHASE?

A. The Budget Approval phase involves the creation of Transmission's annual budget and schedule for capital projects. This annual budget aligns with the budgeting and budget governance process that Ms. Ostrom addresses in her testimony. Each business unit, including Transmission, works closely with corporate financial performance and reporting to develop capital budgets.

Q. WHAT IS THE FIRST STEP IN THE BUDGET APPROVAL PHASE?

A. The first activity for Transmission in the Budget Approval phase involves the project managers refreshing the cost estimates for previously approved projects. Project managers then enter new proposed project attributes, proposed monthly cash flows, and in-service dates into TamCasting.

Q. AFTER ALL POSSIBLE CAPITAL PROJECTS ARE PLACED IN TAMCASTING, WHAT IS THE NEXT STEP?

A. Our directors and managers, along with other key employees review all possible projects that are entered into TamCasting and represent our proposed budget to determine which should be implemented and included in the Transmission budget.

As many of our Reliability Requirement and Regional Expansion projects are multi-year projects, once these projects have commenced, it is difficult to halt or defund these projects in subsequent budget years. We do, however, examine all capital expenditures for a given year to determine whether they are necessary to carry out the final execution of those projects. As a result, these projects often receive higher priority in our budgeting process as they move forward toward completion. Similarly, given our MISO Tariff obligations, we have little latitude to deny specific Interconnection projects from being included in our budget.

After we determine the portion of our budget that is committed to these projects, we examine our remaining budget and determine how to prioritize the remaining proposed projects and previously planned projects. We prioritize those projects based on the risk and urgency of a particular project.

After a series of meetings to discuss all of the potential projects and the appropriate prioritization given funding availability, the result is an initial capital budget for Transmission.

Q. AFTER THE INITIAL BUDGET IS DETERMINED, WHAT IS THE NEXT STEP?

A. Transmission's proposed capital budget then moves through the corporate budgeting process discussed by Ms. Ostrom. Based on the corporate budgeting process, a higher or lower percentage of the Company's overall budget may be allocated to Transmission depending on the priority of needs at the Company level. Once the corporate budgeting process is complete, Transmission may be able to maintain its capital budget as proposed or it may need to adjust based on the thresholds established at a corporate level.

Q. WHAT HAPPENS IF TRANSMISSION DOES NOT RECEIVE ALL OF ITS REQUESTED FUNDING?

A. The capital projects that Transmission identifies as necessary in a particular year often exceed the budget thresholds established at a corporate level. When this occurs, our directors and managers reexamine our budget and reprioritize our capital projects based on the new thresholds. During the reprioritization process, we carefully evaluate all of the system risks associated with each of these budget reduction scenarios and reevaluate all mitigation plans that may mean a suboptimal operation of the transmission system but ensure our compliance with all mandated system reliability standards.

Q. CAN YOU PROVIDE AN EXAMPLE OF A PROJECT THAT WAS ELIMINATED FROM TRANSMISSION'S CAPITAL BUDGET BASED ON THIS REPRIORITIZATION?

A. Yes, a project called "Larimore Substation Conversion" was proposed for inclusion in our 2023 capital budget but was deferred until 2024 due to budget reprioritization between both the Transmission organization and Distribution organization.

Q. IF YOU ARE ABLE TO DEFER THIS PROJECT, IS IT EVEN NECESSARY?

A. The Larimore Substation Conversion project is needed but we determined that it can be delayed one year. The project involves replacing a transformer in the existing substation in Larimore, North Dakota with a higher capacity transformer. The project also includes converting several distribution feeders from 4 kV to 12.5 kV to better serve the existing area distribution load. While the project is needed, system conditions allow the project to be deferred for a year to allow more pressing need in the transmission system to be addressed.

Q. DOES THIS BUDGETING PROCESS THAT YOU HAVE DESCRIBED ENSURE THAT TRANSMISSION'S CAPITAL ADDITIONS ARE REASONABLE AND NECESSARY IN EACH YEAR OF THIS MULTI-YEAR RATE PLAN?

A. Yes. This budgeting process results in a reasonable budget that is representative of the capital investments needed to maintain the reliability of the transmission system used to provide electric service to our customers, provide necessary upgrades to the regional transmission system, comply with NERC reliability requirements and other policy drivers, meet system capacity needs, and ensure the health of existing assets.

Q. PLEASE EXPLAIN THE PROCESS YOU FOLLOW TO MANAGE CAPITAL EXPENDITURES AFTER BUDGET APPROVAL.

A. From a financial perspective, capital projects are reviewed on a monthly basis after approval to compare the monthly budget to actual funds spent. We perform a monthly project forecasting exercise to ensure we have a steady and dependable flow of financial information regarding capital expenditures. Through this process, the entire transmission project portfolio is reviewed and consolidated each month. Any variances are immediately addressed. All projects that indicate they may be outside of allowed variances are reevaluated and assessed internally by the Transmission business unit and may be escalated to the corporate level. For larger projects, greater than or equal to $10 million, we adhere to the corporate guidelines to seek "re-approval" of projects outside allowed variances.

Review is also performed to compare year-to-date actual performance with year-to-date and year-end forecasts. Deviations are identified, and recommendations to meet financial targets are reviewed and approved. Changes are reported to the financial performance and planning group, which monitors capital spending. The Transmission business unit is expected to manage its capital additions to its capital budget once that budget has been developed, fully-vetted, and approved. The budgeting process and accountability tools allow us to do so.

C. Capital Investment Trends for 2017 to 2020

Q. FOR 2017 TO 2019, WHAT WERE THE PRIMARY DRIVERS FOR TRANSMISSION'S CAPITAL ADDITIONS?

A. From 2017 to 2019, our capital investments were focused on in-servicing several large Regional Expansion projects. This included the remaining CapX2020 projects, which were completed in 2017, as well as the Badger Coulee Project, a MISO designated MVP, that was completed in 2018 (also referred to as the La Crosse–Madison Project).

In 2019, our capital investments in Regional Expansion declined as our investments in Asset Renewal projects grew. This greater focus on Asset Renewal projects was due to interrelated factors including a reassessment of our transmission line inspection practices and the age and condition of our transmission facilities.

Q. WHY DID THE COMPANY REASSESS THE TRANSMISSION LINE INSPECTION PROGRAMS?

A. We reassessed our inspection programs due to the occurrence of California wildfires in 2018 and 2019 that were caused by Pacific Gas & Electric Co. (PG&E) transmission lines. In particular, the 2018 Camp Fire, caused by sparks from faulty utility equipment, was one of the deadliest and most destructive wildfires in California history. While wildfires are not a high risk in the Midwest, they did propel us to examine our system, our inspection practices, and our Asset Renewal programs to ensure that we are making the necessary investments to address the risks we face here, such as high winds or ice storms. As a result of this review, we determined a need to increase the frequency of our transmission line inspections to ensure that faulty equipment is identified and addressed in a timely manner.

Q. PLEASE DESCRIBE THESE CHANGES TO THE TRANSMISSION LINE INSPECTIONS.

A. Beginning in 2018, we increased our foot patrols from every six years to every four years, and increased ground line inspections which are completed for each part of our system on a 12-year cycle. The frequency of these inspections was benchmarked against industry practices. In 2019, we also started using Unmanned Aerial Vehicles (drones) to inspect our transmission facilities. In 2020, we inspected over 1,000 miles of line on the NSP Transmission System.

Q. WHAT WAS THE IMPACT OF THESE INCREASED INSPECTIONS?

A. This increase in inspections has resulted in more defects being identified that require repair or replacement. For instance, in 2019, a much higher percentage of poles were ranked as Priority 2 and required immediate replacement as compared to the previous two years. Specifically, in 2017 and 2018, the percentage of poles ranked as Priority 2 were 1.9 percent and 2.2 percent, respectively, of the total number of poles tested. In, 2019 the percentage of poles ranked as Priority 2 rose to 5.0 percent of the total poles tested.

Given the condition and age of certain of our facilities, this increase in identified defects due to increased inspections is consistent with our expectations. Our wood and steel structures have an expected useful life of 70 years. While steel structures tend to have slightly longer useful lives as compared to wood structures, we utilize 70 years as a guideline for the useful life of both our wood and steel structures. Currently, there are over 500 miles of transmission line that are supported by structures that are 70 years old or older on the NSP

Transmission System. While the age of a structure is not necessarily indicative of its condition, older assets are most often the assets where condition may be an issue given the length of time that they have been exposed to the elements.

Q. HOW DID THE COMPANY MAINTAIN THESE TRANSMISSION FACILITIES ABSENT HIGHER CAPITAL INVESTMENT IN PRIOR YEARS?

A. Prior to 2019, we were able to keep these aging transmission assets in working order through general maintenance (O&M costs) and either refurbishment or replacement of specific components when they reached the end of their service life. As part of these refurbishment projects, we replaced only specific components that were in poor condition, like cross-arms, insulators, and some poles, with the existing conductor remaining in-place. Through these refurbishments, we were able to extend the life of these assets by 10 to 20 years depending on asset condition and the scope of the refurbishment.

Q. DO THE CHANGES YOU DISCUSS ABOVE IMPACT TRANSMISSION'S ASSET RENEWAL CAPITAL BUDGET FOR THE MULTI-YEAR RATE PLAN (MYRP) PERIOD?

A. Yes. Over the last five years, we have started to see that assets that were previously refurbished need wholesale replacement. This can either be because of the aggregate condition of all of the components of a circuit (poles, cross-arms, insulators, and conductor) or where the existing design, such as the current pole size, limit our ability to refurbish other components. An example of this would be our lines with copper conductors. When this conductor ages, it becomes brittle. Ideally, we want to replace the conductor and insulators; however, if the existing poles are not able to accommodate the weight of the new conductor and insulator, we need to rebuild the entire line rather than simply replacing the conductor and insulators. As a result, in 2019, we began to identify more lines that required a complete rebuild due to the fact that refurbishment was no longer an option. Given that rebuilds often require more lead time to plan and implement, many of these rebuild projects were set in motion to be placed in service as part of our capital budgets for 2021 through 2023.

Q. DID TRANSMISSION INCREASE ITS CAPITAL INVESTMENTS IN OTHER BUDGET CATEGORIES DURING THIS PERIOD?

A. Yes. During 2017 to 2019, Transmission also completed work on several smaller Reliability Requirement projects with several of these projects going in service in 2018. These projects included the Pomerleau Lake Substation and the Gleason Lake Substation projects in Minnesota in 2018 and the Minot Load Serving Project in North Dakota in 2018 and the Maple River Red River 115 kV Project in North Dakota in 2019.

From 2017 to 2019, we also made increasing expenditures in the Physical Security and Resiliency category to make necessary physical security upgrades at eighteen of the Company's substations in Minnesota and installed additional security measures such as cameras, lighting, and controlled access points at 41 of the Company substations in Minnesota, North Dakota, and Wisconsin.

Q. FOR 2017 TO 2020, HOW DID YOUR CAPITAL INVESTMENTS BREAK INTO THE CAPITAL BUDGET GROUPINGS?

A. Table 1 below shows the breakdown of capital expenditures by each capital budget grouping for 2017 to 2020. (I note that 2020 is a forecast based on six months of actuals and six months of forecast.)

Table 1

2017-2020 Capital Expenditures
(Excludes AFUDC)
(Dollars in Millions)

NSPM and NSPW (both Total Company)	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Forecast**
Asset Renewal	$68.8	$69.5	$104.4	$116.2
Reliability Requirement	$52.9	$75.1	$47.5	$34.0
Interconnection	$1.9	$10.8	$6.8	$20.2
Physical Security and Resiliency	$17.6	$16.5	$19.0	$12.9
Regional Expansion	$76.9	$60.1	$14.6	$40.7
Communication Infrastructure	$3.3	$1.9	$0.9	$0.7
Totals	**$221.4**	**$233.8**	**$193.2**	**$224.7**

Table 2 below shows the breakdown of capital additions by each of the six capital budget groupings for 2017 to 2020. The amounts presented in my testimony include costs recovered or intended to be recovered through the TCR Rider. Mr. Halama will discuss the TCR Rider in greater detail. I am including these amounts here as these projects are part of our overall Transmission capital budget.

Table 2

2017-2020 Capital Plant Additions
(Includes AFUDC)
(Dollars in Millions)

NSPM and NSPW (both Total Company)	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Forecast**
Asset Renewal	$57.4	$72.3	$77.6	$106.7
Reliability Requirement	$55.9	$96.2	$39.1	$43.2
Interconnection	$7.6	$9.8	$6.7	$21.9
Physical Security and Resiliency	$16.9	$14.4	$15.8	$18.1
Regional Expansion	$74.0	$183.5	$22.3	$3.9
Communication Infrastructure	$8.7	$4.5	$0.3	$1.3
Totals	**$220.5**	**$380.7**	**$161.8**	**$195.1**

Q. CAN YOU EXPLAIN THE SIGNIFICANT INCREASE IN CAPITAL ADDITIONS IN 2018 AS COMPARED TO 2017 AND 2019?

A. Yes. This is primarily due to the in-servicing of a large Regional Expansion project, Badger Coulee, with $170.2 million in capital additions in 2018. Additionally, in 2018, we also placed in service several larger value Reliability Requirement projects as compared to 2017 and 2019. The Reliability Requirement projects completed in 2018 include the Gleason Lake Substation and Pomerleau Lake Substation projects in Minnesota and the Minot Load Serving Project in North Dakota. Finally, from 2017 to 2018, our investments in Asset Renewal projects increased due to the need to replace a greater number of aging transmission assets in poor condition. For example, in 2018 the Company completed 36 discrete End-of-Life Relay projects as opposed to completing only eight of these replacements in 2017. Similarly, in our Major Line Rebuild and Major Line Refurbishment programs, we saw a limited number of projects completed and total dollars in-serviced in 2017 (four projects totaling $18,101) as compared to the completion of eight projects in these same programs in 2018 for a total plant addition of $11.1 million.

Q. PLEASE EXPLAIN THE DECREASE IN CAPITAL ADDITIONS IN 2019 AS COMPARED TO 2018?

A. This decrease is due to reduced investments in Regional Expansion projects and Reliability Requirement projects in 2019 as compared to 2018. With regard to Regional Expansion projects, there are limited investments in this category in 2019 as the remaining CapX2020 projects were completed in 2017, and Badger Coulee was completed in 2018. Also, due to the timing of in-service dates, there was only one material Reliability Requirement project that went into service in 2019 – the Maple River to Red River project that had capital additions of $20.7 million. This is a significant decrease as compared to 2018.

Further, our investments in Communication Infrastructure projects was reduced in 2019 due to the Frame Relay program coming to an end. The Frame Relay program replaced antiquated analog communication equipment in substations with new equipment more suitable to function with modern telecommunications circuits, whether owned and operated by the Company or by third-party telecommunications providers.

Q. WHAT ARE THE COMPANY'S FORECASTED CAPITAL ADDITIONS FOR 2020?

A. In 2020, we are forecasting approximately $195.1 million in capital additions, which is an increase from our 2019 actuals of $161.8 million. Capital projects that will be completed in 2020 include the Wilson Substation Conversion Project, which is a Reliability Requirement Project, nine specific transmission line rebuild projects as part of the Major Line Rebuild program, and fourteen

Physical Security projects from the Physical Security and Resiliency category. These Physical Security projects improve the security measures at our substations to protect against potential physical threats. For instance, in 2020, the Company installed the following security improvements at a substation in central Minnesota: a new 10 foot tall expanded metal ballistic rated security fencing, a 20 foot long M40 crash rated security arm at the main gate, and upgraded the substation electrical service from 100 kVA to 250 kVA.

Q. WHY ARE TRANSMISSION'S CAPITAL ADDITIONS FOR 2020 HIGHER THAN 2019?

A. In 2020, we saw an increase in Asset Renewal projects including nine transmission line rebuild projects. In 2020, we also increased investments in Interconnection projects like the Jamaica Substation that was constructed to increase load serving capacity in the southeastern metro area due to a large industrial customer's expansion. Transmission's other investments in Interconnection projects in 2020 will include retroactive self-funded network upgrade payments to generation developers for Interconnection projects that were completed prior to 2020. I discuss self-funded network upgrade projects in greater detail later in my testimony.

Q. HAS THE CURRENT GLOBAL PANDEMIC AFFECTED TRANSMISSION'S CAPITAL FORECAST FOR 2020?

A. The pandemic has had a minor impact on our 2020 capital forecast presented here, which was established in the summer of 2020. In certain cases, we have seen minor schedule delays, but all projects that were scheduled to be placed in service in 2020 will be placed in service before year-end. Transmission has updated our financial budgets for 2020 to reflect our best estimate of these financial impacts, and we will continue to adjust as more information related to

COVID-19 pandemic impacts is available. This is consistent with the approach we would take related to any of the various ways our business may evolve during a given period.

Q. ARE THESE IMPACTS FACTORED INTO TRANSMISSION'S FORWARD-LOOKING CAPITAL BUDGETS AS WELL?

A. Yes. At this time, we do not anticipate a major change to the capital work we have planned for 2021 to 2023. We continue to monitor the work and our budgets in light of the pandemic, as we do under all circumstances.

D. Overview of Capital Investments for 2021 to 2023

Q. WHAT ARE TRANSMISSION'S CAPITAL BUDGETS FOR 2021 TO 2023 BY CAPITAL BUDGET CATEGORY?

A. Table 3 and Table 4 (and Figures 3 and 4) below provide both planned capital expenditures and additions for 2021 to 2023.

Table 3

2021-2023 Forecasted Capital Expenditures
(Includes AFUDC)
(Dollars in Millions)

NSPM and NSPW (both Total Company)	2021 Budget	2022 Budget	2023 Budget
Asset Renewal	$150.6	$215.5	$171.3
Reliability Requirement	$90.3	$76.2	$62.7
Interconnection	$46.0	$46.2	$47.5
Physical Security and Resiliency	$41.1	$34.7	$30.3
Regional Expansion	$41.3	$52.1	$95.4
Communication Infrastructure	$10.5	$21.8	$36.1
Totals	**$379.8**	**$446.5**	**$443.3**

Table 4

2021-2023 Forecasted Capital Plant Additions
(Dollars in Millions)

NSPM and NSPW (both Total Company)	2021 Budget	2022 Budget	2023 Budget
Asset Renewal	$132.2	$148.4	$182.3
Reliability Requirement	$62.9	$73.9	$27.9
Interconnection	$41.0	$33.3	$40.3
Physical Security and Resiliency	$33.9	$43.4	$30.4
Regional Expansion	$74.7	$18.1	$0.0
Communication Infrastructure	$9.3	$22.9	$35.8
Totals	**$354.0**	**$340.0**	**$316.7**

Figure 3

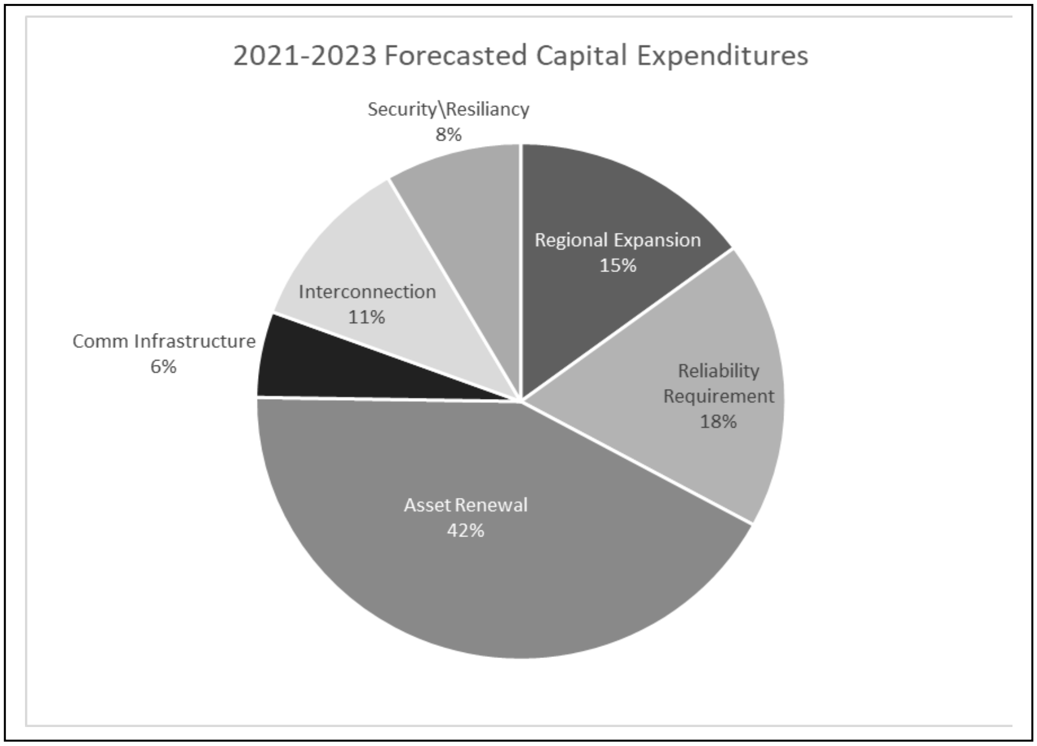
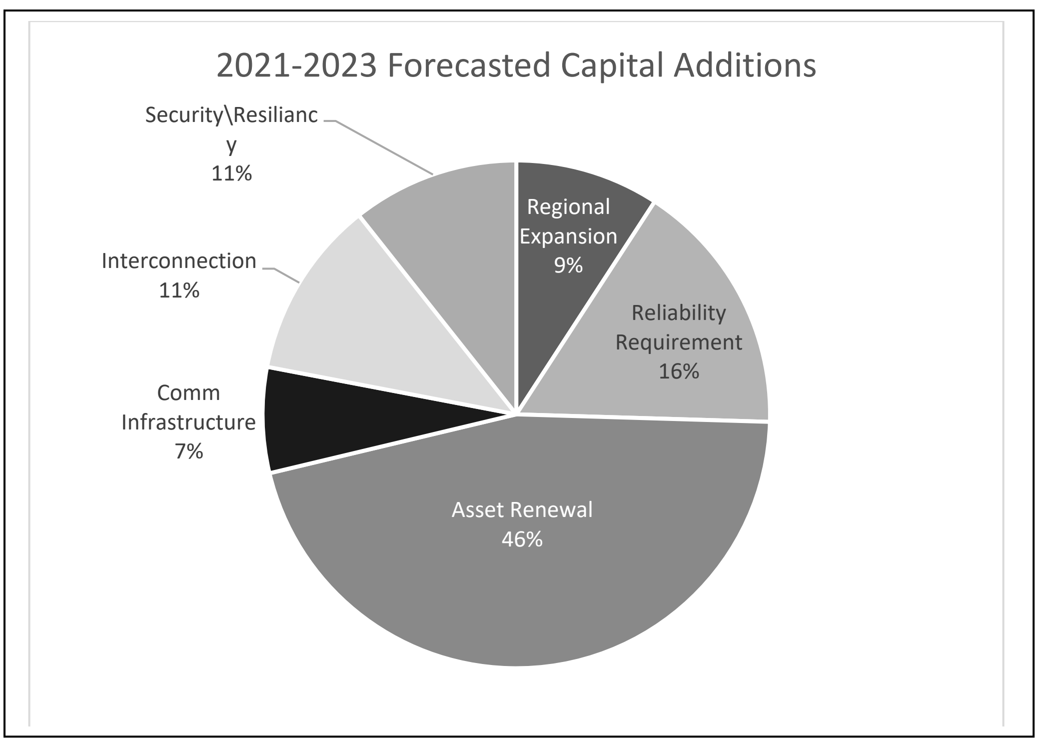


Figure 4



Q. HOW DO TRANSMISSION CAPITAL INVESTMENTS IN 2021 TO 2023 COMPARE TO HISTORICAL TRENDS?

A. Our 2017 through 2023 capital expenditures and capital additions are set forth in Table 5 and Table 6 below. As these tables illustrate, our capital additions for the MYRP period for nearly every capital budget category, with the exception of Regional Expansion, are substantially higher than our historical investment trends. I discuss the reasons for these increasing investments below.

Table 5

2017-2023 Actual and Forecasted Capital Expenditures
(Excludes AFUDC)
(Dollars in Millions)

NSPM and NSPW (both Total Company)	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Budget**	**2022 Budget**	**2023 Budget**
Asset Renewal	$68.8	$69.5	$104.4	$116.2	$150.6	$215.5	$171.3
Reliability Requirement	$52.9	$75.1	$47.5	$34.0	$90.3	$76.2	62.7
Interconnection	$1.9	$10.8	$6.8	$20.2	$46.0	$46.2	$47.5
Physical Security and Resiliency	$17.6	$16.5	$19.0	$12.9	$41.1	$34.7	$30.3
Regional Expansion	$76.9	$60.1	$14.6	$40.7	$41.3	$52.1	$95.4
Communication Infrastructure	$3.3	$1.9	$0.9	$0.7	$10.5	$21.8	$36.2
Totals	**$221.4**	**$233.8**	**$193.2**	**$224.7**	**$379.8**	**$446.5**	**$443.4**

Table 6

2017-2023 Actual and Forecasted Capital Plant Additions (Includes AFUDC) (Dollars in Millions)

NSPM and NSPW (both Total Company)	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Asset Renewal	$57.4	$72.3	$77.6	$106.7	$132.2	$148.4	$182.3
Reliability Requirement	$55.9	$96.2	$39.1	$43.2	$62.9	$73.9	$27.9
Interconnection	$7.6	$9.8	$6.7	$21.9	$41.1	$33.3	$40.3
Physical Security and Resiliency	$16.9	$14.4	$15.8	$18.1	$33.8	$43.4	$30.4
Regional Expansion	$74.0	$183.5	$22.3	$3.9	$74.7	$18.1	$0.0
Communication Infrastructure	$8.7	$4.5	$0.3	$1.3	$9.3	$22.9	$35.8
Totals	**$220.5**	**$380.7**	**$161.8**	**$195.1**	**$354.0**	**$340.0**	**$316.7**

Q. WHAT IS DRIVING THE INCREASED INVESTMENT IN ASSET RENEWAL FOR 2021 TO 2023 AS COMPARED TO HISTORICAL TRENDS?

A. During the term of this multi-year rate plan, Transmission will be making increasing investments in Asset Renewal projects to address the condition of our aging transmission line facilities. As I noted earlier, our increased investment in Asset Renewal started in 2018, and that trend continues through the MYRP period. These investments arose, in part, from the review of our system, our inspection practices, and our Asset Renewal programs that was spurred by the devastating wildfires in California in 2018. While wildfires are not a high risk in the Midwest, they are representative of other risks that our system must be equipped to handle to ensure reliable and safe service. These risks include ice storms or windstorms, such as the derecho that hit the Midwest in August 2020.

As I noted earlier, this review resulted in Xcel Energy increasing the frequency of inspections and, in 2019, utilizing drones to help with these more frequent and more extensive inspections. Transmission uses a defect priority rating system to identify which assets require immediate action (Priority 1 or Priority 2) as well as those that require near-term action (Priority 3 or Priority 4), and those that require monitoring (Priority 5).

These increased and more comprehensive inspections in turn identified a number of defects on our facilities, as we expected given the age of our system. The average life expectancy for wood and steel transmission lines is approximately 70 years. Table 7 below provides a summary of the approximate age of our steel and wood transmission facilities for both NSPM and NSPW.

Table 7

NSPM and NSPW Transmission Facilities

Circuits approximately 70 years old or older by mileage	Circuits approximately 60 years old or older by mileage	Circuits approximately 50 years old or older by mileage
518 miles	1,325 miles	2,854 miles

Over the last five years, we found that assets that we previously repaired or refurbished are now requiring more extensive repairs such as a wholesale rebuild or a more extensive refurbishment. Given that these larger Asset Renewal projects often require more lead time to plan and implement, these projects were set in motion to be placed in service as part of our budgets for 2021 through 2023. As a result, our capital additions in our Major Line Rebuild and Major Line Refurbishment programs are forecasted to be higher than in 2017 to 2019. This increase in investment over prior years is due to both the number of facilities requiring work as well as the extent of the work that will be done.

Q. CAN YOU PROVIDE AN EXAMPLE OF A MAJOR LINE REBUILD PROJECT THAT IS PLANNED TO BE COMPLETED DURING THE MYRP PERIOD?

A. Yes, one of the specific Major Line Rebuild projects that will be completed during this MYRP period is the rebuild of the approximately 16-mile Belgrade to Paynesville 69 kV line. This line was originally constructed in 1940 and contains approximately 328 structures. Of these 328 structures, 192 contain defects, with some structures containing multiple defects, for a total of 314 defects on this line. In the past five years, there have been more than 20 line outages on this line. Due to the fact that there are known defects on more than half of the structures of the line, rather than simply replace one or two structures, we must rebuild the entire line.

Q. WHAT IS DRIVING THE INCREASED INVESTMENT IN RELIABILITY REQUIREMENT PROJECTS FROM 2021 TO 2023 AS COMPARED TO HISTORICAL TRENDS?

A. We will also be making steady increases in our Reliability Requirement category through specific projects such as the Bayfield Loop Project in Wisconsin that will go in service in 2022, our TACT program that has multiple projects that go in service throughout the period of the multi-year rate plan necessary to comply with NERC Standard TPL-001-4, and the HibTac 500 kV project that is planned to go in-service in 2021; these projects are described in more detail later in my testimony. In addition, capital expenditure for Reliability Requirement projects are also increasing starting in 2021 due to a number of planned projects that will increase reliability to the system but do not go in service until after 2023.

Q. WHAT IS DRIVING THE INCREASE IN INTERCONNECTION PROJECTS FROM 2021 TO 2023 AS COMPARED TO 2017 TO 2019?

A. As I noted above, as of September 1, 2020, there are 107.6 gigawatts of generation in the MISO queue. Of this total, 24.6 gigawatts are located in the MISO West region that includes Minnesota. To accommodate these new generators, the vast majority of which are wind and solar, the Company will need to make increasing investments in Interconnection projects over the term of the multi-year rate plan. I note that these Interconnection projects generally are paid for by the interconnection customer, but in certain circumstances, Xcel Energy may, pursuant to the MISO Tariff, decide to self-fund these network upgrades and then receive payments over a 20-year term from the interconnection customer. As such, these Interconnection projects essentially pay for themselves although the timing of these reimbursements may differ depending on the project.

Q. IS TRANSMISSION INCREASING ITS INVESTMENTS IN OTHER CAPITAL BUDGET CATEGORIES DURING THE TERM OF THE MULTI-YEAR RATE PLAN?

A. Yes. We will also be doubling our efforts related to Physical Security projects in the Physical Security and Resiliency category to improve and enhance the physical security at our critical substation assets in compliance with NERC's CIP-014 standard. As I noted earlier, the CIP-014 standard is relatively new (adopted in 2014 and modified in 2015), and we spent several years assessing our system. As a result of those assessments, we are now planning to implement several security-upgrade projects at key substations.

We will also be making increasing investments in our Communication Infrastructure category between 2021 to 2023 as we continue our efforts to privatize Xcel Energy's communication network infrastructure across the NSPM and NSPW service territories to improve SCADA, teleprotection, and remote engineering access, in addition to corporate services. This privatization will also decrease response time for restoring network outages and reduce our exposure to cybersecurity threats through the publicly accessible network provided by third-party telecommunication companies.

Q. ARE ANY CAPITAL BUDGET CATEGORIES WITH DECLINING CAPITAL ADDITIONS DURING THE MYRP PERIOD?

A. Yes. The Regional Expansion capital budget is currently forecasted to decline over the MYRP term. The capital additions in 2021 are higher than prior years due to the bulk of the Huntley–Wilmarth Project being placed in service, but the capital additions then decline for 2022 and 2023. I note that towards the end of the MYRP, we will be making capital expenditures to support new Regional Expansion projects that we expect will arise from MISO's MTEP21 that will be finalized in December 2021. We anticipate that these projects will not be placed in service during the term of this MYRP.

Q. WHAT KINDS OF CHANGES COULD OCCUR THAT MAY LEAD TO A RE-PRIORITIZATION OF YOUR INVESTMENTS AND CHANGE THE PERCENTAGES THAT YOU INVEST IN EACH CAPITAL BUDGET GROUPING DURING THE TERM OF THE MULTI-YEAR RATE PLAN?

A. There are several reasons we may need to reprioritize capital investments in a particular year or over several years. For example, a new NERC requirement could require Transmission to make investments to comply with the requirement in a particular year. As a result, Transmission may need to increase its investments in the Reliability Requirement category while at the same time reducing investments in another budget category.

Q. WHY IS THE ABILITY TO CHANGE THESE INVESTMENT PERCENTAGES IMPORTANT TO THE COMPANY AND YOUR CUSTOMERS?

A. When we make adjustments to our capital investment plans, we do so to better serve our customers' and our Company's most urgent needs in the most cost-effective way. When the need arises to accelerate a project or develop a new project, we assess the situation to make sure we are doing so for the right reasons and in a prudent way. Similarly, we assess potential project delays or cancellations to make sure we are still meeting business and customer needs in a reasonable way.

Q. EVEN IF YOUR INVESTMENT PERCENTAGES CHANGE FROM THE CURRENT FORECAST, WILL TRANSMISSION STILL WORK TO MANAGE ITS OVERALL CAPITAL INVESTMENTS WITHIN ITS OVERALL BUDGET?

A. Yes. While our investments in particular capital budget groupings may change to address unanticipated issues, ultimately, we will invest as necessary to meet our overall goals of safe and reliable transmission of energy for our customers.

E. Major Planned Investments for 2021 to 2023

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The multiyear rate plan statute, Minn. Stat. § 216B.16, subd. 19, requires that a utility provide "a general description of the utility's major planned investments over the plan period." This section of my testimony discusses the major planned investments Transmission anticipates in 2021 through 2023. The State of Minnesota jurisdictional amounts for each capital addition are included as Exhibit___(IRB-1), Schedule 2.

Q. HOW DID TRANSMISSION IDENTIFY ITS MAJOR PLANNED INVESTMENTS OVER THE PLAN PERIOD?

A. To identify these investments, we looked for those unique projects that require a greater than normal quantity of Transmission resources to complete and that contribute a significant amount to our budgeted capital additions.

Q. WHAT MAJOR PLANNED INVESTMENTS DOES TRANSMISSION ANTICIPATE COMPLETING OVER THE MULTI-YEAR RATE PLAN PERIOD?

A. As depicted in Table 8, we anticipate undertaking three major planned investments between 2021 and 2023. These investments include two Asset Health programs – NSPW Major Line Rebuild and NSPM Major Line Rebuild – and one Regional Expansion project, the Huntley–Wilmarth Project.

Table 8

Transmission Major Planned Investment Projects

	Capital Additions (Includes AFUDC) (Dollars in Millions)		
	2021	**2022**	**2023**
NSPM Major Line Rebuild	$11.2	$21.3	$63.9
NSPW Major Line Rebuild	$13.5	$15.1	$11.6
Huntley–Wilmarth 345 kV Project	$73.2	$4.3	$0.0

These major planned investments, as well as the additional key capital projects we anticipate completing in 2021, 2022, and 2023 are discussed in more detail below.

Q. DOES THE COMPANY PLAN TO RECOVER ANY OF THESE PROJECTS THROUGH THE TCR RIDER?

A. Yes. The Huntley–Wilmarth 345 kV Project will continue to be recovered through the TCR Rider. I am including this project here as it also qualifies as a major planned investment during the plan period. Mr. Halama will provide additional information on TCR Rider recovery of this project.

F. Key Capital Additions for 2021 to 2023

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I describe the main projects under each of the capital budget groupings I identified earlier. Unless otherwise stated, all dollar figures are at the NSPM and NSPW Total Company level. These capital additions are presented in State of Minnesota Electric Jurisdiction form in Exhibit___(IRB-1) Schedule 2.

1. Asset Renewal Projects

Q. WHAT IS THE PRIMARY CHALLENGE FACING TRANSMISSION RELATED TO ASSET RENEWAL?

A. The primary challenge that Transmission faces related to Asset Renewal projects is the number of facilities that will require investment in the coming years to maintain the reliability and safety of our transmission system. Our organization is charged with maintaining a large and aging transmission infrastructure. While transmission facilities generally have long lifespans, these facilities do not last forever. Generally speaking, transmission structures have an average useful lifespan of approximately 70 years. On the NSP Transmission System, there are more than 500 miles of transmission line that are over 70 years old and another 1,300 miles of transmission line that are between 60-70 years old. Likewise, substation transformers have an expected life of between 50 to 65 years and 217 of NSPM's 675 substation transformers are 50 years old or older.

We do not simply replace a transmission asset due to its age, however. Instead, the Company examines both the condition and performance of our aging facilities to determine which facilities are in greatest need of replacement. We also prioritize replacement of aging facilities based on which facilities are most likely to fail and then which equipment will have the biggest impact on the transmission system when it does fail.

Q. WHY ARE INVESTMENTS IN ASSET RENEWAL PROJECTS INCREASING OVER THE TERM OF THIS MULTI-YEAR RATE PLAN?

A. Over the term of this multi-year rate plan, we will be making greater investment in Asset Renewal programs and projects to address the declining condition of our aging transmission facilities. This increase in investments in this area is the result of interrelated factors. As I discussed earlier, one of the key events that eventually led to greater investment in this category was the California wildfires in 2018. While wildfires are not a big risk in the Midwest, they highlighted for our Company and the industry the need to ensure that transmission assets are safe, reliable, and able to withstand extreme events.

In response, we examined our Asset Renewal programs, our inspection frequency, and our investment strategy. One outcome of this examination was more frequent and more comprehensive inspections of our facilities that resulted in identification of more deficiencies. This in turn lead to a need to increase our budgets to make these necessary repairs, refurbishments, or rebuilds. Moreover, while we have been making steady investments in the maintenance and repair of our transmission assets, many of our assets are at the point where they require wholesale replacement or rebuild rather than less costly repairs or refurbishments.

Q. PLEASE EXPLAIN HOW INSPECTIONS ARE USED TO IDENTIFY ASSET RENEWAL PROJECTS.

A. The Company performs various types of assessments on the transmission line facilities at different points in time. Beginning in 2018, we began increasing our foot patrols from every six years to every four years and increased ground line inspections which are completed on all structures on a 12-year cycle. In 2019, we also started using Unmanned Aerial Vehicles (drones) to inspect all of our all FAC-003 (200 kV and above) transmission facilities on an annual basis.

Q. HOW DOES TRANSMISSION EVALUATE THE CONDITION OF ITS FACILITIES?

A. Transmission utilizes a defect priority rating system to rank the condition of our transmission facilities. This rating system utilizes a ranking from Priority 1 to Priority 5, with Priority 1 ranking indicating that a component requires immediate action. I summarize this ranking system in the table below.

Table 9

Defect Priority Rankings

Priority Ranking	Maintenance Priority and Maintenance Action	Asset Management Implication
Priority 1	Emergency; Immediate Action Required	Failed Component with or without service interruption
Priority 2	Emergency; Urgent Action Required	Failure imminent-component damaged or no longer suitable for intended use. Service not yet interrupted but failure or service interruption is imminent.
Priority 3	High Priority	Asset renewal required-significant wear, corrosion or damage to warrant action plan.
Priority 4	Medium Priority	Asset renewal recommended-moderate to minimal wear, corrosion, or damage to warrant action plans.
Priority 5	Low Priority	Minimal maintenance-minor wear, corrosion, etc. but still functional condition for the intended purpose.

The components that are designated as Priority 1 or Priority 2 require urgent action and therefore are typically funded out of our Storm and Emergencies programs. Those assets labeled Priority 3 to Priority 5 require action but not immediately, so the replacement and repair of these components is typically funded through our other Asset Renewal programs such as our Major Line Rebuild or End-of-Life programs.

Q. WHAT IS THE NEXT STEP AFTER AN ASSET IS CATEGORIZED BY PRIORITY?

A. In these assessments, the Company identifies those transmission lines that require rebuilding, and specific projects are subsequently developed and prioritized using the Company's Line Prioritization Matrix, which is a tool developed by the transmission line performance group that uses internal and external information to quantitatively rank each transmission circuit. Each line is scored and ranked against each other incorporating the following drivers:

- Importance
  - What happens if the circuit has an outage
  - Operational concerns
  - Design concerns
- Reliability
  - Frequency of outages
  - Duration of outages
  - Benchmarking rating
- Condition Assessment
  - Incorporates two scoring groups
    - Field Engineer's Field Assessment
    - Transmission Asset Management System (TAMS) Identified Defects
      - Defect count and severity
      - Repair cost estimates

Through the assessment process, the Company may identify defective line circuits requiring a full rebuild as early as five years before the rebuild is needed. However, we typically budget lines for this program only two to three years in advance because upgrades in the system area, storms and emergencies, and changing system needs may alter the overall asset health score for identified lines beyond the two- to three-year window. The Company identifies, budgets for, and develops specific projects during our annual budget process and on the basis of the total asset health score of the line as determined by the Line

Prioritization Matrix. These individual projects are then prioritized against the rest of the planned Transmission capital portfolio. Lastly, the Company budgets for projects in the three- to five-year range based on the remaining projects that are in the top quartile of the Line Prioritization Matrix following the historical trends of this program.

Q. WHAT ARE THE KEY ASSET RENEWAL PROGRAMS AND PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. There are eight key Asset Renewal programs that have assets that will be placed in service between 2021 and 2023:

1. NSPM and NSPW Major Line Rebuild program;
2. NSPM and NSPW Major Line Refurbishment program;
3. NSPM and NSPW Storms & Emergencies (S&E) Line program;
4. NSPM and NSPW Relay End-of-Life (ELR) program;
5. NSPM and NSPW Substation Breaker ELR program;
6. NSPM and NSPW Transformers ELR program;
7. NSPM Nuclear Substation ELR program; and
8. NSPM and NSPW Line ELR program.

There are also two key Asset Renewal projects that will be placed in service during the term of the multi-year rate plan:

- W3203 Briggs-La Crosse Line Upgrade Project; and
- NSPM and NSPW Group 1 Switch Replacements Project.

a. Asset Health Programs

Q. PLEASE DESCRIBE THE NSPM/NSPW MAJOR LINE REBUILD PROGRAM.

A. The Major Line Rebuild program for NSPM and NSPW represents projects that rebuild large segments of transmission lines on the NSP Transmission System that have a concentrated number of defects that contribute to poor line performance. These projects are typically required either because the existing line circuits are at risk for increased outage frequency or because the number of structural defects on the circuit makes it unreasonable to refurbish only the defective portions. A rebuild project scope requires complete wreck-out/removal of the physical line assets, which are then replaced with new line assets (e.g., structures, conductor, switches) either within the existing right-of-way (ROW) or with minor, targeted right-of-way expansion to accommodate outage constraints and safe construction practices.

Q. WHAT PLANT ADDITIONS ARE BUDGETED FOR 2021 TO 2023 AS PART OF THE MAJOR LINE REBUILD PROGRAM?

A. The Company has budgeted $96.3 million for the NSPM Major Line Rebuild program ($11.2 million in 2021; $21.2 million in 2022; and $63.9 million in 2023). The Company has budgeted $40.2 million for the NSPW Major Line Rebuild program ($13.5 million in 2021; $15.1 million in 2022; and $11.6 million in 2023).

Q. WHAT IS DRIVING THE INCREASED INVESTMENT IN MAJOR LINE REBUILDS OVER THE TERM OF THE MULTI-YEAR RATE PLAN?

A. These increased investments are driven by both the condition and age of our transmission assets. As I discussed earlier, until recently we have been able to maintain the majority of our assets through either O&M repairs, replacement of specific components when they are at the end of their service life, or refurbishment projects that extend the life of our assets by 10 to 20 years depending on asset condition and the scope of the refurbishment. Recently, our inspections are revealing that lines that were previously refurbished are in need of replacement due to the cumulative condition of the asset (poles, cross-arms, insulators, and conductor), as well as lines where their general composition, like conductor type, framing, and pole sizes would not safely allow for refurbishment. As a result, we need to increase our investments in our Major Line Rebuild programs to rebuild these lines.

Q. CAN YOU PROVIDE INFORMATION ABOUT A SPECIFIC REBUILD PROJECT THAT HAS BEEN IDENTIFIED FOR 2021 TO 2023?

A. Yes. The Avon–Albany project involves rebuilding an approximately seven-mile segment of this 69 kV transmission line (also known as Line 0795), which is over 60 years old. This transmission line originates at Great River Energy's (GRE) West St. Cloud Substation in St. Joseph, Minnesota and runs westerly approximately 25 miles to the Millwood Tap Switch in Freeport, Minnesota. This line is critical to the reliability of this area because it serves the Company's as well as other utilities' distribution loads in the area.

Through the Company's Line Prioritization Matrix, the Company identified Line 0795 as being a poor performer due to its age and condition. The 1953 vintage line consists of direct embedded cedar wood poles. Many of the poles are past their useful life and over the years, many have been replaced through the Storm and Emergencies program due to their poor condition. Due to the number of structures and other associated equipment (cross-arms and conductors) requiring replacement, it is now more cost-effective to do an entire rebuild of this line rather than replace individual components. This project will be placed in service in 2022 and has a total plant addition of $5.4 million.

Q. PLEASE DESCRIBE THE NSPM/NSPW MAJOR LINE REFURBISHMENT PROGRAM.

A. The Major Line Refurbishment program for NSPM and NSPW encompasses a group of targeted projects to replace specific transmission line components, such as defective cross-arms, poles, and other line appurtenance components. This program differs from the Major Line Rebuild program in that the Major Line Rebuild program involves the complete removal and replacement of existing assets; whereas the Refurbishment program addresses specific defects on an entire line segment (breaker to breaker), replacing all like property units on the line segment.

The Company identifies these defective components as at or near failure by means of routine foot patrols, aerial patrols, or Field Engineer's Field Assessment (which occurs only as required by damage reports-an estimated two percent of all lines annually). By refurbishing specific components of a line segment, and rather than rebuilding an entire line, the Company's intent is to increase circuit reliability and performance and extend the residual circuit life by between 10 to 20 years, at a lower cost than a full line replacement.

Similar to our Major Line Rebuild program, the Company utilizes its assessment of the transmission system to help identify specific projects, which are then developed and prioritized in accordance with the Company's line prioritization matrix. As with the Major Line Rebuild program, each transmission line is scored and ranked against each other based on the drivers noted above.

As with the Major Line Rebuild program assessment process, the Company may identify defective line circuits requiring refurbishment as early as five years before repairs are necessary. However, we typically budget lines for this program only two to three years in advance because upgrades in the system area, storms and emergencies, and changing system needs may alter the overall asset health score for identified lines beyond the two- to three-year window. The Company identifies, budgets for, and develops specific projects during our annual budget process and on the basis of the total asset health score of the line as determined by the Line Prioritization Matrix. These individual projects are then prioritized against the rest of the planned Transmission capital portfolio. Lastly, the Company budgets for projects in the three- to five-year range based on the remaining projects that are in the top quartile of the Line Prioritization Matrix following the historical trends of this program.

Q. WHAT PLANT ADDITIONS WILL OCCUR FROM 2021 TO 2023 AS PART OF THE MAJOR LINE REFURBISHMENT PROGRAM?

A. The Company has budgeted $34.5 million for the NSPM Major Line Refurbishment program ($11.8 million in 2021; $12.9 million in 2022; and $9.8 million in 2023). The Company has budgeted $27.1 million for the NSPW Major Line Refurbishment program ($9.5 million in 2021; $12.6 million in 2022; and $5.0 million in 2023).

Q. CAN YOU PROVIDE INFORMATION ABOUT A SPECIFIC REFURBISHMENT PROJECT THAT WILL BE COMPLETED BETWEEN 2021 AND 2023?

A. Yes, included in this program is a refurbishment of the Company's 69 kV transmission line between the Company's Westgate Substation, in Eden Prairie, Minnesota and the Company's Excelsior Substation in the western Minneapolis suburbs. This refurbishment project encompasses the entire length of the line, which is approximately 11 miles. The scope of the project includes the removal of all existing wood cross-arms. The wood cross-arms have decayed over time and are beyond their useful life. These assets will be replaced with new horizontal post insulators. In addition, the project includes the complete removal and replacement of 32 poles that have been identified as defective though our comprehensive inspection program. In total, approximately 185 structures will be modified, and 32 wood poles will be replaced.

Q. PLEASE DESCRIBE THE NSPM/NSPW STORMS AND EMERGENCIES (S&E) LINE PROGRAM.

A. The S&E Line program replaces and repairs equipment that has failed due to a storm event or that is identified through condition assessment as having a high probability of failure and cannot wait for the next normal budget cycle for replacement (i.e., either Priority 1 or Priority 2). This work is typically performed in response to weather events, unforeseen events, and other unscheduled maintenance work that, if not completed, puts the equipment at imminent risk of failure. The work typically includes the replacement of arms, poles, conductor, insulators, and other line appurtenances.

Q. WHAT RECENT TRENDS HAVE YOU SEEN IN THE S&E LINE PROGRAM?

A. We have recently seen more poles classified as Priority 2 (i.e., requiring immediate replacement through our S&E program) than in prior years. Specifically, in 2017 and 2018, the percentages of poles categorized as Priority 2 were 1.9 percent and 2.2 percent respectively of the total number of poles tested. In 2019, the number of poles classified as Priority 2 rose to 5 percent of the total poles tested. While it is too early to tell if this is a trend or if 2019 is an anomaly, it does underscore the importance of continued inspections and continued funding for this program to address these urgently needed replacements.

Q. HOW DOES TRANSMISSION DETERMINE THE BUDGET FOR THE S&E LINE PROGRAM?

A. The Company sets its budget for this program based on a historical annual average because the nature of the work to be performed is not known until the time of an incident. The forecast is then adjusted throughout the year based on actual incidents, while factoring in the probability of storm or emergency events for the remainder of the calendar year.

Based on historical average budgeting for this program, Transmission's plant additions for any given year range between $10.0 million and $14.0 million per year. One of the reasons for this budget range is because the Company occasionally experiences late season storms or emergencies for which the physical work and capital expenditure must carry over from one budget year to the next, causing the plant addition to be carried over from one year to the next.

Q. WHAT PLANT ADDITIONS ARE BUDGETED FOR 2021 TO 2023 FOR THE NSPM/NSPW S&E LINE PROGRAM?

A. The Company has budgeted $25.5 million for the NSPM S&E Line program ($8.7 million in 2021; $8.4 million in 2022; and $8.4 million in 2023). The Company has budgeted $12.3 million for the NSPW S&E Line program ($4.0 million in 2021; $5.3 million in 2022; and $3.0 million in 2023).

Q. PLEASE DESCRIBE THE NSPM/NSPW ELR – RELAY PROGRAM.

A. Protective relays monitor power system quantities, typically voltages and currents, and open and close circuits to remove short circuits from the power system.

The ELR – Relay program encompasses projects that target relays for replacement that exhibit poor performance and lack available replacement parts. As transmission infrastructure continues to age or nears or is at its end of life, these components must be changed before failures occur. As the structural integrity of aging assets diminishes, outages will increase in frequency and duration.

While we may identify a number of relays that require replacement as early as five years in advance of the asset's end of life, we typically budget for this program only two to three years in advance. During our annual budget process, the poorest performing relays are added to the budget. These projects are then prioritized against the rest of the planned Transmission portfolio. Budgets for projects in the three- to five-year range are then planned for transmission's remaining relay infrastructure based on age and asset health. The pace of this replacement program may vary because many aging relays may still be functional but do not offer optimal operational performance. As such, the replacement of components identified in this project can be accelerated or decelerated dependent on other Transmission portfolio needs.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2021 TO 2023 FOR THE ELR – RELAY PROGRAM?

A. The Company has budgeted a total of $28.9 million for the ELR – Relay program: $11.0 million for the NSPM ELR – Relay program ($4.8 million in 2021; $1.7 million in 2022; and $4.4 million in 2023) and $17.9 million for NSPW ELR – Relay program ($9.6 million in 2021; $4.3 million in 2022; and $4.1 million in 2023).

Q. CAN YOU PROVIDE AN EXAMPLE OF AN ELR-RELAY PROJECT THAT WILL BE COMPLETED DURING THE TERM OF THIS MULTI-YEAR RATE PLAN?

A. Yes, an example of one of these projects is the replacement and upgrading of the relaying at the Riverside Substation. This project is part of a larger effort to phase out older technology relaying systems on the transmission system. The relays at the Riverside Substation include older electro-mechanical relays as well as first generation microprocessor relays. These types of relays have been targeted for replacement primarily due to poor performance and lack of replacement parts. We have budgeted $1.0 million in capital additions to complete this project in 2021.

Q. PLEASE DESCRIBE THE NSPM/NSPW SUBSTATION BREAKER ELR PROGRAM.

A. The NSPM/NSPW Substation Breaker ELR program targets substation circuit breakers for replacement that have been identified due to poor performance or lack of available replacement parts for repair. As transmission infrastructure ages or nears its expected end of life, components must be changed before failures occur. As the structural integrity of these aging assets diminishes, outages will increase in frequency and duration.

As with the ELR – Relay program, while we may identify a number of circuit breakers through the Substation Breaker ELR program that require replacement as early as five years in advance, typically we budget lines for this program only two to three years in advance. During our annual budget process, the poorest performing circuit breaker projects are included in the budget. These projects are then prioritized against the rest of the planned Transmission portfolio. Budgets for projects in the three- to five-year- range are then planned for based on the age and asset health of these circuit breakers. The pace of this replacement program may vary because many aging breakers may still be functional but do not offer optimal operational performance. As such, the replacement of components identified in this program can be accelerated or decelerated dependent on other Transmission portfolio needs.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2021 TO 2023 FOR THE NSPM/NSPW SUBSTATION BREAKER ELR PROGRAM?

A. The Company has budgeted $10.6 million for the NSPM Substation Breaker ELR program ($5.0 million in 2021; $2.1 million in 2022; and $3.4 million in 2023). The Company has budgeted $13.5 million for the NSPW Substation Breaker ELR program ($5.1 million in 2021; $3.8 million in 2022; and $4.6 million in 2023).

Q. CAN YOU PROVIDE AN EXAMPLE OF A SUBSTATION BREAKER ELR PROJECT?

A. Yes, one of the projects that we plan to complete during the term of this multi-year rate plan is the replacement of all three of the 115 kV circuit breakers at the Fifth Street Substation that serves downtown Minneapolis. The age of these circuit breakers range from 53 to 56 years old. The average service life of a circuit breaker is approximately 50 years. Given the importance of these circuit breakers in serving the large downtown load, a failure of any one of these breakers could result in a large number of customers being without service. As a result, it is important to replace these three circuit breakers at this time given that they are already past their expected service life. We have budgeted $1.3 million in capital additions to complete this project in 2021.

Q. PLEASE DESCRIBE THE NSPM/NSPW TRANSFORMERS ELR PROGRAM.

A. The NSPM/NSPW Transformers ELR program targets transformers for replacement that have been identified due to poor performance or lack of available replacement parts for repair. As transmission infrastructure ages or nears or is at its expected end of life, components must be changed before failures occur. As the structural integrity of these aging transformer assets diminishes, outages will increase in frequency and duration.

As with the other ELR programs (Relays and Circuit Breakers), we may identify a number of transformers through the Transformer ELR program that require replacement as early as five years in advance but, typically we budget lines for this program only two to three years in advance. During our annual budget process, the poorest performing transformers are included in the budget for replacement. These projects are then prioritized against the rest of the planned Transmission portfolio. Budgets for projects in the three- to five-year range are then planned for based on the age and asset health of these assets. The pace of this replacement program may vary because many aging transformers may still be functional but do not offer optimal operational performance. As such, the replacement of components identified in this program can be accelerated or decelerated dependent on other Transmission portfolio needs.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2021 TO 2023 FOR THE NSPM/NSPW TRANSFORMERS ELR PROGRAM?

A. The Company has budgeted $9.1 million in capital additions for the NSPM Transformers ELR program ($0.3 million in 2021; $5.8 million in 2022; and $3.0 million in 2023). The Company has budgeted $13.9 million in capital additions for the NSPW Transformers ELR program ($0.1 million in 2021; $9.4 million in 2022; and $4.4 million in 2023).

Q. PLEASE PROVIDE AN EXAMPLE OF A TRANSFORMER ELR PROJECTS THAT WILL BE COMPLETED DURING THE TERM OF THIS MULTI-YEAR RATE PLAN.

A. One of these projects involves the replacement and upgrade of the 300 MVA Eau Claire Substation transformer and both sets of the tertiary reactors for this transformer. Further, as part of this project, substation grounding and the AC auxiliary system will be brought into alignment with current standards. This project was initiated as part of an ELR review of system transformers. During initial scoping, it was determined that the tertiary reactors for this transformer needed to be replaced since they are in need of significant maintenance and are reaching the end of their life. After identifying the replacement of these reactors, we also examined the transformer and determined that it needed replacement due to detection of degradation of transformer gasses. We further determined that this transformer needed to be upgraded to 448 MVA to allow for future load growth in this area. We have budgeted $6.4 million in capital additions to complete this project in 2022.

Q. PLEASE DESCRIBE THE NSPM NUCLEAR SUBSTATION ELR PROGRAM.

A. This program has been separated from the Company's other ELR programs so that it can more easily be completed in coordination with our Nuclear business unit's compliance needs. The Nuclear Substation ELR program addresses the programmatic replacement of substation equipment at the substations that serve the Monticello and Prairie Island nuclear generating plants. The timing of these replacements is designed to align Transmission's substation replacement activities with power plant refueling and maintenance activities at these two nuclear facilities. The equipment identified for replacement consists largely of circuit breakers, switches, relays, and power transformers. While the program can be flexible from year to year, replacement of these facilities is necessary to maintain the ability of the transmission system to transport the energy generated by these plants to customers.

Q. WHAT PLANT ADDITIONS WILL OCCUR FROM 2021 TO 2023 FOR THE NSPM ELR NUCLEAR PROGRAM?

A. The Company has budgeted $20.2 million in capital additions for the NSPM ELR Nuclear program ($3.6 million in 2021; $7.3 million in 2022; and $9.3 million in 2023).

Q. PLEASE DESCRIBE THE NSPM/NSPW LINE ELR PROGRAM.

A. The Line ELR program for NSPM and NSPW encompasses projects that target the replacement of defective cross arms, poles, and other line appurtenance components on the NSP Transmission System that have been reported as defective by routine foot and aerial patrols and are nearing their end of life. Overall, the Line ELR program extends the life of NSP transmission line assets when full line replacement is not necessary. Line ELR is utilized primarily when the individual defect has occurred, but the overall line segment is otherwise in sound condition with many years of additional life remaining.

Q. HOW DOES THE LINE ELR PROGRAM DIFFER FROM THE MAJOR LINE REFURBISHMENT PROGRAM DISCUSSED ABOVE?

A. The Major Line Refurbishment program replaces specifically identified defective transmission line property units (cross-arms or poles or other line appurtenances) when the majority of similar property units of the same vintage and design have been identified as defective on a line circuit. Any property units found to be in good operational condition are left in place.

In contrast, the Line ELR program replaces only individual transmission line property units that are defective, but not similar property units of the same vintage and design that are generally in good operating condition.

When defects are identified through patrols, typically one to three years in advance, they are classified as either Major Line Refurbishment or Line ELR, and they are budgeted and executed. These two programs are managed separately because the severity of the identified defects on a circuit, along with the frequency of the defects, determines which program's budget will be utilized.

Q. WHAT PLANT ADDITIONS WILL OCCUR FROM 2021 TO 2023 FOR THE LINE ELR PROGRAM?

A. The Company has budgeted $11.9 million for the NSPM Line ELR program ($3.6 million in 2021; $3.7 million in 2022; and $4.5 million in 2023). The Company has budgeted $7.7 million for the NSPW Line ELR program ($2.9 million in 2021; $2.3 million in 2022; and $2.5 million in 2023).

Q. PLEASE DESCRIBE THE GROUP 1 SWITCH REPLACEMENTS PROJECT.

A. The Group 1 Switch Replacements project is similar to many of our End-of-Life projects. The difference is that this project specifically targets transmission line switches that no longer function as originally designed or have reached the end of their useful life. A Group 1 Switch Replacement project is utilized primarily when an individual switch on a transmission line is found to be defective, but the transmission line segment is otherwise in sound condition with many years of additional life remaining.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2021 TO 2023 AS PART OF THE GROUP 1 SWITCH REPLACEMENTS PROJECT?

A. The Company has budgeted $7.1 million for the NSPM Group 1 Switch Replacements ($2.4 million in 2021; $2.2 million in 2022; and $2.5 million in 2023). The Company has budgeted $3.6 million for the NSPW Group 1 Switch Replacements ($1.5 million in 2021; $1.1 million in 2022; and $1.1 million in 2023).

Q. DESCRIBE THE W3203 BRIGGS-LA CROSSE LINE UPGRADE PROJECT.

A. This project involves rebuilding the W3203 Briggs – La Crosse line. This is a 10-mile, 161 kV transmission line located between the Company's Briggs Road Substation located near Holmen, Wisconsin and La Crosse Substation in La Crosse, Wisconsin. In 2016, this project was first identified as Major Line Refurbishment project due to the age and condition of certain elements of the line. However, during the 2019 annual transmission planning analysis, this line was identified as being close to the thermal limits under contingency conditions. As a result, it was recommended that the conductor of the line be upgraded. In the 2020 annual transmission planning analysis, this line was identified as exceeding thermal limits in the 2024 Summer peak and light load cases under multiple contingencies in the area and as requiring mitigation under NERC's TPL-001-4 requirements. As a result, the scope of the project was expanded to include upgrading the conductor size and all terminal end switches to meet NERC's TPL-001-4 requirements. Upgrading the conductor will also require all of the existing poles to be replaced in order to accommodate the new conductor. This project is in the preliminary design and engineering phase with construction scheduled to begin in 2022. This project is currently scheduled to be placed in service in 2023 and has total plant additions of approximately $11.2 million.

2. Reliability Requirement Projects

Q. WHAT IS DRIVING THE COMPANY'S INVESTMENTS IN RELIABILITY REQUIREMENT PROJECTS?

A. NERC develops and enforces reliability standards on all transmission owners, operators, and users. The Company performs transmission planning studies to identify necessary upgrades to the system to ensure compliance with NERC standards. Through these studies, transmission planners evaluate all various alternatives to meet the identified electrical needs for the system and select the option that considers the incremental impact of the project for future needs in the area and best meets the long-term electrical needs of the area in a cost effective- manner. This category of projects also includes transmission improvements that are needed to improve the reliability in our system where the operating voltage of the system being improved is below NERC regulation; these projects would typically be adding operational redundancy to our 34.5 kV, 69 kV and 88 kV transmission systems.

Q. WHAT WOULD BE THE IMPACT OF EITHER FORGOING OR DEFERRING A RELIABILITY REQUIREMENT PROJECT?

A. Deferring or forgoing a necessary Reliability Requirement project could impact system reliability. Further, if the project is needed to meet a NERC reliability standard, the Company could be found to be in violation of NERC reliability standards.

Q. WHAT ARE THE KEY RELIABILITY REQUIREMENT PROJECTS THAT TRANSMISSION WILL PLACE IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. There are three key Reliability Requirement projects and programs that will be placed in-service between 2021 and 2023:

- Bayfield Loop Project;
- TACT program; and
- Hibbing Taconite 500 kV Project.

Q. PLEASE DESCRIBE THE BAYFIELD LOOP PROJECT.

A. The Bayfield Loop Project, which is also referred to as the Bayfield Second Circuit Transmission Project, is needed to improve system reliability by adding redundancy to the system by constructing a second 34.5 kV transmission line and two new substations in the Bayfield Peninsula area of Wisconsin. The proposed new transmission line would extend approximately 19 miles, and would connect the two new substations: the Fish Creek Substation, located approximately four miles west of Ashland, Wisconsin, and Pikes Creek

Substation, located approximately two miles west of Bayfield, Wisconsin.[2] The project will increase electric reliability and reduce power outages across the Bayfield Peninsula by providing voltage support and a second source of power to the east side of the Bayfield Peninsula. The proposed 34.5 kV transmission line is called the "second circuit" or "second source" because there is an existing 34.5 kV line extending to Bayfield. The Public Service Commission of Wisconsin granted a Certificate of Authority for the Bayfield Loop Project on February 7, 2020.[3]

Grading for the new Fish Creek Substation will begin in 2020 and construction of the Pikes Creek Substation and the transmission line are planned to commence in 2021. This project is currently scheduled to be placed in service in 2022. The project1 has total plant additions of approximately $43.7 million ($0.2 million in 2021; $41.1 million in 2022; and $2.4 million in 2023).

Q. PLEASE DESCRIBE THE TACT PROGRAM.

A. NERC requires utilities to perform annual assessments of their transmission system and to demonstrate plans to keep the transmission system within specified voltage, thermal, and stability limits throughout the 10-year planning period. The Company performs this annual assessment by participating in the MISO MTEP process, which is an RTO lead reliability study effort. MISO MTEP participants work together to analyze the transmission system for deficiencies (high voltage, low voltage, lines or transformers beyond their rated capability, etc.) and to ensure compliance with NERC Standard TPL-001-4.

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[2] *Application of N. States Power Co.-Wisc. for a Certificate of Auth. to Construct the Bayfield Second Circuit Transmission Project, to be Located in Bayfield Cnty., Wisc.*, PSCW Docket No. 4220-CE-182, APPLICATION FOR A CERTIFICATE OF AUTHORITY (Mar. 8, 2019).

[3] *Application of N. States Power Co.-Wisc. for a Certificate of Auth. to Construct the Bayfield Second Circuit Transmission Project, to be Located in Bayfield Cnty., Wisc.*, PSCW Docket No. 4220-CE-182, FINAL DECISION (Feb. 7, 2020).

Generally speaking, NERC Standard TPL-001-4 requires that transmission system be designed and constructed to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies such as loss of one or more elements of the system. The MISO MTEP studies the performance of the system using 1-year, 5-year, and 10-year future models. When deficiencies are identified, MISO transmission owners create a plan to manage the transmission system to stay within the specified limits. The MISO MTEP typically finalizes its annual study in December of each year.

The Company established the TACT program to allocate resources necessary to address reliability issues on the NSP Transmission System that are identified in the annual MISO MTEP studies.

For both NSPM and NSPW the TACT program has total plant additions of approximately $19.2 million ($5.9 million in 2021; $8.2 million in 2022; $5.1 million in 2023).

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT PROJECTS THAT WILL COMPRISE THE TACT PROGRAM BUDGET DURING THE MULTI-YEAR RATE PLAN?

A. A discrete project in this program budget includes replacing both circuit breakers and upgrading three switches at the Company's West Coon Creek Substation. The West Coon Substation is connected to the Company's Coon Creek Substation via a 115 kV transmission line. The two circuit breakers at the West Coon Substation need to be rated for 3000 amps rather than their current rating of 2000 amps. This is due to the fact that, if one of those circuit breakers opens, the other breaker would not be able operate because of its lower capacity rating (2000 amps) compared to the 3000 amps capability that would be coming from the 115 kV transmission line. The scope of work includes replacing both circuit breakers and upgrading three switches at the West Coon Creek Substation.

Q. PLEASE DESCRIBE THE HIBBING TACONITE (HIBTAC) 500 KV PROJECT.

A. The HibTac 500 kV Project is located southwest of the City of Chisholm, Minnesota. This project includes the removal, replacement, and relocation of an approximately 3.0-mile segment of an existing 500 kV line that is located on Cleveland-Cliffs, Inc.'s land where HibTac has mining operations. The existing transmission line was built on right-of-way authorized by a license agreement rather than an easement. The license agreement includes provisions that the Company would move the transmission line if requested by licensor. On January 15, 2017, HibTac formally requested that the Company remove the line from six parcels to allow expansion of the HibTac mine.

The Commission granted the Company a minor alteration approving construction of the HibTac 500 kV Project on March 2, 2020.[4] Foundation work commenced in October 2020 and construction will be complete in 2021. This project has total plant additions of $15.5 million in 2021.

Q. WHY IS THE COMPANY REQUIRED TO PAY FOR THIS PROJECT INSTEAD OF THE CUSTOMER?

A. The license agreement for this portion of the 500 kV line included a condition that stated that after the first 15 years of the license agreement the costs for relocating the 500 kV line would be borne by the Company rather than HibTac.

[4] *In the Matter of the Application for a Minor Alteration of Xcel Energy's 500 kV Transmission Line 5702*, Docket No. E002/MC-19-758, ORDER (Mar. 2, 2020).

3. Interconnection Projects

Q. WHAT IS DRIVING TRANSMISSION'S INTERCONNECTION INVESTMENTS?

A. Under our tariff, we are required to make the necessary transmission upgrades to accommodate interconnection requests. There are three general types of Interconnection projects that drive our interconnection investments: transmission interconnections, load interconnections, and generation interconnections. Transmission interconnections are where one utility is requesting to interconnect a transmission line to our transmission system. Load interconnections are where a new substation serving electric load is needed and is requesting to interconnect to our transmission system, or an existing load serving substation is being modified. Generation interconnections are where a new generator is requesting to interconnect to our transmission system.

Q. WHAT IS DRIVING THE INCREASE IN INTERCONNECTION PROJECTS BETWEEN 2021 TO 2023?

A. The increase in Interconnection projects is driven primarily by the number of interconnection requests currently pending in the MISO queue. These new generation facilities require certain transmission upgrades in order to interconnect to the transmission system as a result, the Company is making increasing investments to complete these necessary upgrades.

Q. WHAT ARE THE KEY INTERCONNECTION PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. During 2021 to 2023, the key Interconnection programs/projects are: (1) NSPM/NSPW self-funded network upgrade (SFNU) projects; (2)

J512/J569/J587/J590 HNA-SCO interconnection; and (3) IA Tariff Fund Program.

Q. PLEASE DESCRIBE THE NSPM/NSPW SFNU PROJECT.

A. The SFNU are a group of projects to support network upgrades necessary to accommodate generation interconnections. Specifically, network upgrades are defined as the additions, modifications, and upgrades to the transmission system that are required at or beyond the point at which the generation interconnection facilities connect to the transmission system. Generally, these network upgrades are either new facilities, such as transmission lines or substations, or occasionally modifications and/or additions to existing transmission substations or to transmission lines connecting to an existing substation.

Q. WHY ARE THE COSTS FOR THESE SFNU PROJECTS INCLUDED IN THIS RATE CASE RATHER THAN BEING RECOVERED FROM THE INTERCONNECTION CUSTOMERS?

A. The MISO tariff allows transmission owners like Xcel Energy the option to unilaterally choose to self-fund network upgrades without requiring interconnection customers to make upfront payments for these upgrades. Prior to the in-service date of the network upgrades, Xcel Energy will enter into a Facilities Service Agreement (FSA) with the interconnection customer to repay the actual cost for the network upgrade that allows Xcel Energy to earn a return, typically over a period of twenty (20) years, with payments beginning the month after the network upgrades are place into service. Xcel Energy has decided to exercise the self-funding option for all network upgrades associated with MISO generation interconnection projects. The payments that will be made by generators in accord with these FSAs over the term of the multi-year rate plan are included in the transmission revenues budget in this case, which reduce the retail revenue requirement and keep retail customers whole. As such, these Interconnection projects essentially pay for themselves, although the timing of these reimbursements may differ depending on the project.

Q. WHAT IS THE BUDGET FOR SFNU PROJECTS OVER THE TERM OF THE MULTI-YEAR RATE PLAN?

A. The Company has budgeted $46.3 million for the NSPM SFNU Project ($0.5 million in 2021; $16.5 million in 2022; and $29.2 million in 2023). The Company has budgeted $6.0 million for the NSPW SFNU Project ($0.1 million in 2021; $1.9 million in 2022; and $4.0 million in 2023).

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR THE NSPM/NSPW SFNU PROJECTS?

A. Currently, there are approximately 14 renewable generation interconnection projects in the MISO queue that will require network upgrades to accommodate their interconnection to the MISO transmission system. The budget for these potential projects is developed by a facilities study performed by Xcel Energy engineers at the request of MISO. These facilities studies include high-level cost estimates of the potential network upgrades required based on general location of the renewable generation source and proposed output of the renewable generation. We relied on the cost estimates from these facilities studies to develop the budget for the NSPM/NSPW SFNU projects.

Q. DESCRIBE THE HELENA–SCOTT 345 KV REBUILD PROJECT (J512/J569/J587/J590 HNA-SCO INTERCONNECT PROJECT).

A. The Helena–Scott 345 kV Rebuild Project is an example of an SFNU project but this project has its own budget apart from the overall SFNU project budget due to the fact that it is in the final design phase. This project involves the rebuilding the existing 17-mile Helena–Scott 345 kV transmission line in Scott and Carver counties to increase the capacity of the line to accommodate the interconnection of several new renewable generators. Specifically, MISO generation interconnection studies determined that this line needed to be rebuilt to increase the capacity of the conductor to accommodate the interconnection of four new wind farms in the area: the Blazing Star 2 Wind Project, the Nobles 2 Power Partners Projects, the Walleye Wind Project, and the Invenergy Wind Development Project. To support this higher capacity conductor, the existing lattice and wood H-frame structures will be replaced with new steel H-frame structures. Xcel Energy as the transmission owner of this line is using the self-funding option of the MISO tariff for these network upgrades. At the completion of this rebuild, Xcel Energy will enter into an FSA with each generator to refund their respective costs for these network upgrades. The payments that will be made by these four generators in accord with these FSAs over the term of the multi-year rate plan are included in the transmission revenues budget in this case, which reduce the retail revenue requirement and keep retail customers whole.

This project is currently in the final design phase and construction is expected to commence and be completed in 2021. The Helena – Scott County Rebuild Project (J512/J569/J587/J590 HNA-SCO interconnect project) has total plant additions of approximately $35.8 million in 2021.

Q. PLEASE DESCRIBE THE IA TARIFF FUND PROGRAM.

A. This program is used to fund generation interconnection related transmission capital investments. The specific transmission upgrades in this program have not yet reached the level of specificity to be defined as specific capital projects but nonetheless are expected based on generator's announced plans or interconnection requests in the MISO queue. The Company has budgeted $12.5 million for the NSPM IA Tariff Fund ($0.0 million in 2021; $8.5 million in 2022; and $4.0 million in 2023). The Company has budgeted $9.1 million for the NSPW IA Tariff Fund ($0.0 million in 2021; $6.1 million in 2022; and $3.0 million in 2023).

Q. CAN YOU PROVIDE AN EXAMPLE OF A PROJECT WITHIN THE IA TARIFF FUND PROGRAM?

A. One example is our J569 Rock County Substation project to interconnect a wind generator into the Company's Rock County Substation that will be placed in service in 2021. Another example is the Lismore project to interconnect Nobles Power Cooperative (a GRE cooperative) to Xcel Energy's transmission system to allow for customer load growth by Nobles Power Cooperative. This project will be placed in service in 2021 and has plant additions of $1.4 million.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR THE IA TARIFF FUND PROGRAM?

A. As noted above, the budget for this program is based on historical averages and known Interconnection project requests.

4. Physical Security and Resiliency Projects

Q. WHAT ARE THE MAJOR ISSUES FACING TRANSMISSION WITH REGARD TO PHYSICAL SECURITY AND RESILIENCY?

A. Transmission is focused on maintaining the security of our assets. High voltage transformers comprise less than three percent of transformers in U.S. electric power substations, but they carry 60 to 70 percent of the nation's electric load. Since they serve as vital nodes and carry bulk volumes of electricity, these transformers are critical elements of the nation's electric power grid. They are also the most vulnerable to intentional damage from malicious acts. In April 2013, for example, a substation in California was subject to a coordinated military-type sniper attack that disabled 17 high voltage transformers, rendering this substation useless.

Federal regulatory agencies have since responded to these growing threats by adopting physical security standards for transmission facilities. On March 7, 2014, FERC issued an Order on Reliability Standards for Physical Security Measures, which ultimately led to NERC standard CIP-014 addressing risks due to physical security threats and vulnerabilities. To address these threats and meet this new NERC standard, we are making necessary investments to make our grid more resilient so that we can respond quickly to physical security threats.

Q. WHAT ARE THE KEY PHYSICAL SECURITY AND RESILIENCY PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. The Physical Security and Resiliency projects that will be placed in-service between 2021 and 2023 will arise out of two programs: (1) NSPM/NSPW Physical Security program and (2) the NERC Circuit Protection program.

Q. PLEASE DESCRIBE THE NSPM/NSPW PHYSICAL SECURITY PROGRAM.

A. The NSPM/NSPW Physical Security program was developed to ensure the Company's compliance with the NERC CIP-014 Physical Security Standard.

Additionally, the program aims to improve substation site security where the Company's Protection Services department has identified ongoing theft issues. The purpose of this program is to improve the physical security of the Company's substations. The Company is developing site-specific security plans for specific substations and is obtaining third-party verification of the effectiveness of these plans. These site-specific security plans may include the following security measures: cameras, fencing/barrier improvements, ballistic shielding of identified key substation equipment, site access controls, ground sensory monitoring, and radar technology. This program is planned for 15 discrete substation sites in 2021; additional sites will be identified and evaluated against the most current NERC security standards for inclusion in this program as those standards are updated every two years.

The Company has budgeted $72.0 million for the Physical Security program over the term of the multi-year rate plan ($31.3 million in 2021; $20.3 million in 2022; and $20.4 million in 2023).

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR THE PHYSICAL SECURITY PROGRAM?

A. Our Substation Compliance team and our Protection Services department have identified sites that are highly likely to either a) need to be brought up to the NERC CIP-014 Physical Security Standard or b) have been targets of ongoing theft. As changes to the transmission system regularly occur, those changes may impact a substation location that was not previously required to have the physical security controls as defined under CIP-014. This is because whether or not security controls are required under CIP-014 is dependent on the impact the loss of that substation may have on the bulk electric system. As new transmission projects come forward, Xcel Energy reviews the associated impacted substations to determine whether these locations must now meet the heightened physical security requirements outlined in the NERC CIP-014 standard. A similar reevaluation is performed for sites that have been a target of theft.

The budget for each of the identified sites are estimated at a high level based on existing as-built and record drawings. Each site is then prioritized within the program based on the level of protection required to bring it up to the NERC standard or discourage theft. Each site requires an on-site evaluation by the project team to validate the existing conditions, determine if there are other site conditions that were not identified in the record drawings and update/validate the estimate. This site evaluation is typically done in the year prior to the specific site's in-service date.

Q. PLEASE DESCRIBE THE NERC CIRCUIT PROTECTION PROGRAM.

A. The NERC Circuit Protection program was initiated to comply with FERC Order 754. Under FERC Order 754, the Company must identify single point failures at critical substations with voltages of 200 kV or above and report the results to NERC. The Company has studied the relevant substations and identified certain required modifications to eliminate these single point failures. This program includes capital projects related to separating primary and secondary relaying and adding redundant direct current circuits at several Company-owned substation facilities. This separation allows a back-up battery to continue to provide protection services in the case the primary battery at the substation fails.

The Company has budgeted $17.3 million for the NERC Circuit Protection program ($2.5 million in 2021; $10.6 million in 2022; and $4.3 million in 2023). Under NERC Order 754, substation owners must identify and address deficiencies in their protection and control systems that could pose a risk to the backup response in case a failure occurs. This includes eliminating opportunities for a single point of failure across multiple breakers. NERC Order 754 requires compliance by 2024 so Transmission started this work in 2017 and will ramp up this work in 2022 and 2023 is to ensure that we complete all required work prior to 2024.

Q. CAN YOU PROVIDE AN EXAMPLE OF A PROJECT WITHIN THE NERC CIRCUIT PROTECTION PROGRAM?

A. One of the projects that the Company will be completing to comply with NERC Order 754 is at the Prairie Island Substation where the Company will be adding auxiliary relays to trip the breakers of other transformers in the event that a failure occurs on another substation breaker. This improvement will ensure compliance with NERC Order 754 and improve the reliability of the Prairie Island Substation. This project will be in service in 2021 and has associated plant additions of $1.1 million.

5. Regional Expansion Projects

Q. WHAT ARE THE KEY REGIONAL EXPANSION PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. There are two key Regional Expansion projects that will be placed in-service between 2021 and 2023: (1) the Huntley–Wilmarth 345 kV Project and (2) the Google Data Center Project.

Q. DESCRIBE THE HUNTLEY–WILMARTH 345 KV PROJECT.

A. The Huntley–Wilmarth 345 kV Project is a joint project between Xcel Energy and ITC Midwest and involves the construction of an approximately 50-mile, 345 kV transmission line in southern Minnesota and associated substation modifications. The transmission line will connect Xcel Energy's Wilmarth Substation, located north of Mankato, and ITC's Huntley Substation, located south of Winnebago. The project will also include modifications at both the Huntley and Wilmarth substations to accommodate the new 345 kV transmission line.

The Huntley–Wilmarth Project is needed to reduce congestion on the transmission grid in southern Minnesota and northern Iowa to deliver low-cost electricity to consumers from generation facilities in the area, including wind farms. The project was studied, reviewed, and approved by MISO as a Market Efficiency Project (MEP) in December 2016 as MISO found that the project will reduce congestion on the transmission system, which will improve the efficiency of MISO's energy markets resulting in lower wholesale energy costs. The Commission granted a Certificate of Need and Route Permit for the Huntley–Wilmarth Project on August 5, 2019.[5]

The project is currently under construction and will be placed in service in December 2021, which is the project's MISO designated in-service date. The

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[5] *In the Matter of the Application of Xcel Energy and ITC Midwest LLC for a Certificate of Need and for a Route Permit for the Huntley–Wilmarth 345-kV Transmission Line Project*, ORDER FINDING ENVIRONMENTAL IMPACT STATEMENT ADEQUATE, GRANTING CERTIFICATE OF NEED, ISSUING ROUTE PERMIT, AND REQUIRING ADDITIONAL ANALYSIS, Docket Nos. E002, ET-6675/CN-17-184, TL-17-185 (Aug. 5, 2019).

project has total plant additions of approximately $79.8 million ($2.3 million in 2020; $73.2 million in 2021; and $4.3 million in 2022).

Q. DESCRIBE THE GOOGLE DATA CENTER PROJECT.

A. The Company has negotiated several agreements with Honeycrisp, LLC, an affiliate of Google LLC, that are intended to help bring a new data center to the City of Becker, Minnesota. If the project moves forward, it could generate $600 million in capital investment and presents an opportunity to be one of the largest private economic development endeavors in central Minnesota. To facilitate the development of the possible new data center, the Company sought and received approval from the Commission for several agreements, associated cost recovery, and certain tariff amendments and waivers that would enable the Company to provide retail electric service at transmission voltage to the possible new data center.[6]

Among the several agreements, the Company executed an IA for Retail Electric Service at Transmission Voltage, which provides the terms and conditions for the Company's build-out of certain transmission voltage facilities to support interconnection of the data center. The IA provides different transmission voltage configurations to support varying amounts of data center load in line with the customer's issuance to the Company of a "Notice to Proceed," after which the Company is obligated to construct the necessary facilities at its cost. Should the IA be terminated prior to the conclusion of the 10-year IA period, Honeycrisp, LLC would make a termination payment to the Company

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[6] *In the Matter of the Pet. by N. States Power Co. d/b/a Xcel Energy for Approval of Contracts and Ratemaking Treatment for Provision of Elec. Serv. to Google's Data Center Project*, Docket Nos. E002/M-19-39 and E002/M-19-60, ORDER APPROVING PETITION WITH CONDITIONS (July 15, 2019).

equivalent to the net book value of the transmission facilities as of the date of termination.

The Company also requested and received approval of a one-time waiver from the Company's General Time-of-Day Service Tariff requiring that a customer bear the cost of interconnection upgrades required to serve the customer. Rather than recover these costs directly from Honeycrisp, LLC via a contribution in aid of construction (CIAC), the Company requested – and the Commission granted – authorization to seek recovery of these costs in a future rate case.[7]

The project has forecasted total plant additions from 2021 to 2023 of approximately $15.2 million ($1.4 million in 2021 and $13.8 million in 2022).

Q. WHY IS THE DATA CENTER PROJECT CLASSIFIED AS A REGIONAL EXPANSION PROJECT?

A. In addition to large regional infrastructure, our Regional Expansion Projects also include those projects driven by economic development needs, which is the primary driver for the Data Center project.

6. *Communication Infrastructure Projects*

Q. WHY ARE INVESTMENTS IN COMMUNICATION INFRASTRUCTURE NECESSARY?

A. Communication circuits are required at substations for SCADA, remote engineering access, and teleprotection. In the past, the Company has relied on third-party telecommunication providers for the infrastructure necessary for our SCADA and teleprotection circuits (i.e., communication circuits between

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[7] *Id.* at 23.

our substations and between our substations and our control center). However, many of the telecommunication companies are phasing out their dedicated analog wide area network (WAN) technology and replacing it with Ethernet over fiber optics or other broadband services. These new services, while capable of carrying large volumes of data, are not able to carry the data that we transmit within acceptable performance requirements for the teleprotection of our transmission system. As a result, we need to invest in Company-owned and controlled communication infrastructure using fiber optic cable that will serve our operational and system protection needs without the reliance on and vulnerability to exposure from a publicly available third-party network.

Similarly, cyberattacks pose a credible threat to the reliability of our transmission system as hackers could cause system outages by disabling telecommunications or key pieces of equipment. Every day there are coordinated attempts to infiltrate communication systems and disrupt the transmission grid. Federal regulatory agencies have responded to these growing threats by adopting cybersecurity standards for transmission facilities. The Company-owned telecommunications network we are investing in enables the Company to reduce our exposure to cybersecurity threats from the publicly available service provided by third-party telecommunication providers.

Q. DO THESE INVESTMENTS PROVIDE ANY OTHER BENEFITS?

A. Yes, an additional benefit of these investments is that they will also support the advanced grid and information system (AGIS) initiative and enterprise-wide initiatives by enabling connectivity between all of our substations and corporate offices.

Q. WHAT ARE THE KEY COMMUNICATION INFRASTRUCTURE PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. The key Communication Infrastructure projects that will be placed in service between 2021 and 2023 will arise out of the Communication Network program.

Q. DESCRIBE THE COMMUNICATIONS NETWORK PROGRAM.

A. The Communication Network program aims to privatize Xcel Energy's communication network infrastructure across the NSPM and NSPW service territories, wherever possible, at all transmission and distribution substations for SCADA, teleprotection, and remote engineering access. Specifically, the program addresses aging analog circuit technology and other technology that is anticipated to become obsolete within five years. The Company will then build secure communication architecture for physically isolated operational technology (OT) and information technology (IT) networks from each other to support islanding of the energy management system (EMS) for further cyber security resilience. The program will enable the Company to reduce dependency on third-party circuit providers, which will improve the Company's troubleshooting response time and reduce circuit down time.

The Company has budgeted \$46.7 million for the NSPM Communication Network program (\$3.9 million in 2021; \$17.3 million in 2022; and \$25.5 million in 2023). The Company has budgeted \$20.0 million for the NSPW Communication Network program (\$5.0 million in 2021; \$5.0 million in 2022; and \$9.9 million in 2023).

Q. CAN YOU PROVIDE AN EXAMPLE OF ONE OF THESE COMMUNICATION NETWORK PROJECTS?

A. Yes, one example is at the Company's Rosemount Substation in Rosemount, Minnesota where we will be installing upgraded telecommunication equipment and installing a private communication network path (fiber optic cable) from the substation to a leased fiber optic cable located outside the substation that will only be utilized by the Company for communication within our network.

Q. HOW DID THE COMPANY DEVELOP THE BUDGETS FOR THE COMMUNICATIONS NETWORK PROGRAM?

A. The budget is based on Communication Network infrastructure projects identified and prioritized by our substation communication engineering group for consideration in the capital budget. Communication projects are prioritized based on technical need and proximity to exiting private network infrastructure that is deliberately built out from a reliable core network. These projects are vetted and prioritized against all Transmission projects; and rebalanced and reprioritized across the entire portfolio of projects based on corporate budget requirements. Project costs are estimated using historic costs from prior projects.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE OVERALL LEVEL OF TRANSMISSION CAPITAL COSTS THE COMPANY IS SEEKING TO RECOVER IN THIS RATE CASE?

A. I conclude that our capital forecasts represent an accurate and reasonable projection of our investments over these years and, as shown by the above discussion, are necessary to provide reliable and resilient transmission service for our customers. Finally, the costs included in our 2021 through 2023 capital budgets are representative of the types of work we must and will do year over year. Therefore, these capital forecasts can be relied on to set just and reasonable rates for our customers.

IV. O&M BUDGET

A. O&M Overview and Trends

Q. WHAT IS INCLUDED IN THE TRANSMISSION O&M BUDGET?

A. The Transmission O&M budget includes costs associated with the operation and maintenance of our transmission system. This includes internal and contract labor, employee expenses, fees, and materials. The majority of Transmission's O&M budget is related to internal labor costs as these employees are necessary to plan, construct, operate, and maintain the transmission system on a daily basis.

Q. WHAT ARE THE TRANSMISSION O&M BUDGET CATEGORIES?

A. The Transmission business unit O&M budget consists of six main cost categories: (1) internal labor; (2) contract labor and consulting; (3) employee expenses; (4) fees; (5) materials; and (6) other. I describe these categories in detail later in my testimony.

Q. HOW ARE THE TRANSMISSION BUSINESS UNIT LONG-TERM O&M COSTS TRENDING?

A. From 2017 to 2019, the Transmission business unit has engaged in productivity improvement initiatives, which have resulted in a declining O&M expenses over these years. These efforts have driven improved scheduling and field productivity, resulting in more efficient and effective ways for transmission crews to schedule and complete their work, thus reducing O&M expenditures. Additionally, an industry benchmarking analysis resulted in changes to the Company's repair versus replacement policies to promote replacement over repair for assets that required repeated costly repairs. These initiatives, and the resulting reductions in O&M expense, have been executed to offset ongoing inflationary pressures, as well as pressures resulting from the Company's asset growth. For example, scheduling efficiencies have driven the organization from a 41 percent to a 90 percent average scheduling efficiency. This allows work to be planned and executed in a more efficient manner reducing the overall O&M cost of the work. Some examples of the efforts that led to the increased efficiency include locking in the schedules a week prior, more detailed scheduling, formalized job readiness checklists, minimization of schedule changes, and daily huddles with leadership and crews to discuss daily work plans.

Transmission's forecasted O&M for 2020 is lower than the three-year average of 2017 to 2019. During 2020 our operations were impacted by the COVID-19 public health emergency. In response to the impact that COVID-19 had on our communities, customers, and operations in 2020, Transmission adjusted our operations to keep employees and communities safe as well as to maintain financial flexibility as the Company faced uncertainties about the depth and duration of the impacts of COVID-19. Specifically, Transmission temporarily reduced O&M expenses in 2020 by reducing contractor hours, reduced employee travel, delaying hiring open positions, and scaling back on overtime, where possible without impacting safety and reliability.

Q. WHAT ARE THE TRANSMISSION O&M BUDGETS FOR 2021 TO 2023?

A. As shown in Table 10, we have budgeted $38.2 million for Transmission O&M in 2021, $38.7 million in 2022, and $40.4 million in 2023.

Table 10 also provides our actual O&M costs for 2017 to 2019 and the 2020 forecast for O&M spend (half year actuals and half year forecast). Table 11 provides this same information but allocated to the State of Minnesota Electric Jurisdiction. Exhibit___(IRB), Schedule 3 also provides the Transmission O&M costs by cost category for 2017 to 2019.

Table 10

Transmission O&M Budget by Cost Category
NSPM-Electric
($000,000)

Cost Category	2017 Actual	2018 Actual	2019 Actual	2017 – 2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Internal Labor	$21.40	$22.00	$20.40	$21.30	$20.00	$21.50	$22.10	$22.80
Contract Labor and Consulting	$4.70	$4.50	$4.50	$4.60	$3.90	$4.50	$4.50	$4.40
Employee Expenses	$2.70	$2.90	$2.70	$2.80	$2.30	$3.10	$3.10	$3.10
Fees*	$3.50	$3.50	$3.40	$3.50	$3.50	$3.70	$3.90	$4.20
Materials	$3.60	$3.30	$2.50	$3.10	$1.70	$2.50	$2.40	$2.30
Other	$5.10	$4.10	$2.60	$3.90	$2.60	$2.90	$2.70	$3.60
Total	**$41.00**	**$40.30**	**$36.10**	**$39.20**	**$34.0**	**$38.20**	**$38.70**	**$40.40**

* The "Fees" cost category includes Dues, Fees, and Licenses, which includes professional & utility association dues, land and railroad permits, license fees, as well as NERC and FERC assessments.

Table 11

Transmission O&M Budget by Cost Category
State of Minnesota Electric Jurisdiction
(Net of Interchange Billings to NSPW)
($000,000)

Cost Category	2017 Actual	2018 Actual	2019 Actual	2017 – 2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Internal Labor	$15.8	$16.2	$14.9	$15.6	$14.6	$15.7	$16.1	$16.6
Contract Labor and Consulting	$3.5	$3.3	$3.3	$3.4	$2.8	$3.3	$3.3	$3.2
Employee Expenses	$2.0	$2.2	$2.0	$2.0	$1.7	$2.2	$2.2	$2.2
Fees*	$2.6	$2.6	$2.5	$2.5	$2.5	$2.7	$2.8	$3.1
Materials	$2.7	$2.5	$1.8	$2.3	$1.2	$1.8	$1.8	$1.7
Other	$3.7	$3.1	$1.9	$3.0	$1.9	$2.2	$2.0	$2.6
Total	**$30.3**	**$29.9**	**$26.4**	**$28.8**	**$24.7**	**$27.9**	**$28.2**	**$29.4**

* The "Fees" cost category includes Dues, Fees, and Licenses, which includes professional & utility association dues, land and railroad permits, license fees, as well as NERC and FERC assessments.

Q. DO TRANSMISSION'S O&M EXPENSES FOR 2021 TO 2023 CONTINUE THIS DECLINING TREND FROM 2017 TO 2019?

A. Generally, yes. The Transmission O&M budget for 2021 to 2022 trends lower than 2017 to 2019 actuals, with a slight increase in 2023 as compared to 2017 to 2019 actuals. Overall, the three-year average for these years ($39.1 million) is below the most recent three-year historical average (2017 to 2019) of $39.20 million. This continued decrease is primarily driven by productivity improvement initiatives that have been implemented by Transmission that I discussed earlier.

Q. HOW DOES THE TRANSMISSION O&M BUDGET FOR 2021 TO 2023 COMPARE TO 2019 ACTUALS?

A. Transmission's O&M budget for each of these three years is higher than 2019 actuals by an average of eight percent. The overall increase from 2019 actuals to the 2021 to 2023 O&M budget is driven by increases in: 1) base pay; 2) non-labor inflation; 3) fees; and 4) asset growth and compliance.

Q. WHAT IS DRIVING THE INCREASE IN BASE PAY DURING THE TERM OF THE MULTI-YEAR RATE PLAN?

A. Transmission has budgeted a three percent annual increase in base pay for non-bargaining employees and two and a half percent annual increase in base pay for bargaining employees. Annual base pay increases are discussed in greater detail by Company witness Ms. Ruth K. Lowenthal.

Q. WHAT IS NON-LABOR INFLATION AND HOW DOES IT IMPACT TRANSMISSION O&M EXPENSES?

A. This represents inflation for all non-labor (excluding fees) portions of our O&M budget. Transmission has budgeted a one percent increase in non-labor O&M costs to account for inflation.

Q. WHAT IS DRIVING THE INCREASE IN FEES?

A. Transmission's budget for regulatory fees is based on guidance received from regulatory agencies as to the expected increase in these fees each year. Guidance from NERC and MRO suggested a per year increase of five percent for both organizations. Consistent with this guidance, the Company has budgeted an average increase of 11 percent for 2021 to 2023 as compared to the 2017 to 2019 actuals.

Q. HOW DOES ASSET GROWTH AND COMPLIANCE RESULT IN INCREASED O&M EXPENSES?

A. The Company's asset base is growing by approximately five percent annually as the Company constructs additional miles of transmission line and as the number of substations increases. This asset growth results in increased O&M expenses for both transmission lines and substations. Examples of transmission O&M work that increases as the asset base increases are substation inspections, transmission line inspections, administration and supervision, administrative and general maintenance, battery maintenance, relays, and corrective maintenance.

Q. ARE THERE ANY OTHER REASONS WHY THE TRANSMISSION O&M BUDGET FOR 2021-2023 IS HIGHER THAN 2019 ACTUAL O&M EXPENSES?

A. Yes, 2019 O&M expense is an outlier in that it is $4.6 million below the 2017-2018 historical average. This is the result of the acceleration of certain O&M expenses into late 2018, which then reduced 2019 O&M expenses. The O&M activities and expenditures that were accelerated into 2018 include capacitor bank purchases, oil leak repairs, and addressing outstanding corrective maintenance. Transmission's 2019 O&M spend is also lower due to a backlog of maintenance projects driven by the prioritization of other types of work during 2019. This backlog of maintenance work will be addressed in 2021 through 2023, thus increasing the 2021-2023 O&M budgets as compared to 2019. A portion of these increases have been offset by productivity improvement initiatives, which have been implemented by Transmission. Table 12 summarizes the impacts of these items on the O&M budget.

Table 12

Transmission 2021-2023 Budget vs. 2019 Actual O&M Expenditures
NSPM-Electric
(Dollars in Millions)

Cost Drivers	**Amount of Increase/Decrease**	**Total**
2019 Actual		**$36.10**
Base Pay	$1.20	
Non-labor Inflation	$0.20	
Fees: NERC, Professional and Association Dues, and License Fees	$0.40	
2019 Normalization	$1.00	
Fund Substations Maintenance Backlog	$1.70	
Asset Growth and Compliance	$0.30	
Productivity Improvement Initiatives	($2.80)	
Miscellaneous Other	$0.10	
2021 Budget		**$38.20**
Base Pay	$0.70	
Non-labor Inflation	$0.10	
Fees: NERC, Professional and Association Dues, and License Fees	$0.20	
Asset Growth and Compliance	$0.30	
Productivity Improvement Initiatives	($1.00)	
Miscellaneous Other	$0.20	
2022 Budget		**$38.70**
Base Pay	$0.70	
Non-labor Inflation	$0.10	
Fees: NERC, Professional and Association Dues, and License Fees	$0.30	
Asset Growth and Compliance	$0.30	
Miscellaneous Other	$0.30	
2023 Budget		**$40.40**

Q. HOW DO THE 2021 TO 2023 O&M BUDGETS COMPARE WITH THE 2020 FORECAST?

A. Transmission's O&M budget for each of these three years is higher than the 2020 forecast by an average of 15 percent. The overall increase from the 2020 forecast to the 2021 to 2023 O&M budget is driven by increases in: 1) base pay;

2) non-labor inflation; 3) fees; and 4) asset growth and compliance. In addition, as noted above, our 2020 O&M expenses are lower due to several reductions made in response to COVID-19.

Q. HOW DOES THE 2022 O&M BUDGET COMPARE TO THE 2021 BUDGET?

A. The 2022 O&M budget is one percent higher than the 2021 budget. This is due to slight increases in: 1) base pay; 2) non-labor inflation; 3) fees; and 4) asset growth. These increases are partially offset by the realization of additional productivity improvement initiatives implemented by Transmission, resulting in reduced O&M expenditures.

Q. HOW DOES THE 2023 O&M BUDGET COMPARE TO THE 2022 BUDGET?

A. The 2023 O&M budget is four percent higher than the 2022 budget. This is driven by increases in: 1) base pay; 2) non-labor inflation; 3) fees; and 4) asset growth.

Q. HOW HAS THE COVID-19 PANDEMIC AFFECTED TRANSMISSION'S O&M FORECASTS FOR 2021 AND BEYOND?

A. The COVID-19 pandemic has not materially changed Transmission's O&M forecasted costs for 2021 through 2023. Our 2020 O&M budget reflects one-time reductions discussed above but these reductions are not sustainable as the core work of Transmission, operating and maintaining our transmission system, must continue in spite of the pandemic.

B. O&M Budgeting Process

Q. HOW DOES THE COMPANY SET THE O&M BUDGET FOR THE TRANSMISSION BUSINESS UNIT?

A. As with our capital budget, the O&M budget for the Transmission business unit is built using a bottom-up approach. Each budget manager reviews their needs, factoring in work plans as well as any anticipated efficiency gains for the coming years, and develops budgets in accordance with those needs and anticipated efficiency improvements. As part of this bottom-up process, the field operations and construction units review those facilities that need repairs to extend their asset life, addressing issues like broken insulators, loose hardware, woodpecker damage, broken or damaged guy wires, etc. In this way, Asset Renewal projects are a driver of the O&M budgeting process. The individual manager budgets are then consolidated for a total Transmission O&M budget and analyzed for reasonableness and accuracy as compared to recent actual trends. This process includes normalizing the actual spend for those expenses that are not expected to continue into the budget year due to changes in business conditions or one-time events. The total Transmission business unit budget is compared to the overall Company targets, which are discussed further in Ms. Ostrom's Direct Testimony. If the budget is greater than the overall Company targets provided to Transmission, the needs are prioritized with the most critical needs funded first and the least critical needs funded last.

Q. DOES TRANSMISSION EVER NEED TO CHANGE THE ALLOCATION OF O&M FUNDS DURING THE FINANCIAL YEAR?

A. Yes, the Transmission business unit has had to change the allocation of O&M funds during the financial year. Unexpected operational or regulatory events, such as additional NERC compliance requirements, during the year can cause additional unplanned transmission O&M costs. When this occurs, we make every effort to re-evaluate activities within the Transmission business unit to absorb the unexpected costs.

Q. HOW OFTEN DOES TRANSMISSION RE-EVALUATE ITS O&M BUDGET?

A. The Transmission business unit re-evaluates the business needs annually in development of the O&M budget. As needs change, the budget is prioritized to fund the most critical needs first. If the funding required for critical needs is greater than the Company target provided to the Transmission business unit, the critical needs that are not funded within the targets provided are brought to the Company to be prioritized along with the needs of the other business units. For example, if a new NERC compliance requirement is implemented that will cause a substantial change in O&M expenditures and was not contemplated in the targets provided by the Company, additional funding may be requested by the Transmission business unit to cover that need.

Also, during any given year, we are routinely monitoring our O&M actual expenditures versus their associated budgets and identifying any variances of significance as they materialize. As budget pressures are identified in certain areas or programs, options are reviewed to mitigate those pressures. One mitigation option would be the reallocation of funds from other areas, where budgeted work of a lower priority or more discretionary nature in the short-term may be reallocated to cover the programs experiencing the budget pressures. If the amount needing funding cannot be funded prudently within the overall Transmission business unit O&M budget, the issue is brought forward to the Company as a request to increase the overall O&M target for the Transmission business unit.

Q. PLEASE EXPLAIN HOW TRANSMISSION MONITORS ITS O&M EXPENDITURES.

A. The Transmission business unit is supported by a dedicated finance team. The finance team prepares monthly reporting for the Transmission business unit that includes reviews of the current month actual versus budget, year-to-date actual versus budget, and year-end forecast versus target. This reporting is reviewed on a monthly basis with the Transmission leadership team, where concerns or issues are also discussed.

Q. HOW DOES THE TRANSMISSION BUSINESS UNIT O&M BUDGET PROCESS AND GOVERNANCE COMPARE TO INDUSTRY PRACTICE?

A. The process the Transmission business unit uses in the development of the O&M budget is consistent with the practices used in the other business units across the Company. As discussed above, the budget development is accomplished through a bottom-up approach where each budget manager develops their budget based on identified work plans and efficiency gains for the budget year and prioritized based on the most critical activities to ensure the Company targets are met. During the year, governance is accomplished through the monthly reporting and monitoring of performance as well as formal tracking of changes to the year-end targets by director within an operating company, as discussed above. Any changes to the year-end targets within the Transmission business unit are approved by the Senior Vice President of Transmission. Any changes to the overall Transmission business unit targets is brought forward to the Company for consideration. Further discussion of the overall Company budget process and governance is discussed in the Direct Testimony of Ms. Ostrom.

C. O&M Budget Detail

1. Internal Labor

Q. WHAT INTERNAL LABOR COSTS ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT O&M BUDGET?

A. This category represents the O&M portion of salaries, straight time labor, overtime, and premium time for internal employees. An attrition factor of four percent is also applied, which reduces labor costs to account for retirements, hiring delays, and other employee transfers. These amounts include costs for both NSPM employees and the appropriate allocation of Xcel Energy Services employees. For capital construction-focused positions, the vast majority of the labor costs are allocated to capital; however, some labor costs are charged to O&M activities like employee meetings, training, and administrative functions.

Q. WHAT CHANGES IN INTERNAL LABOR COSTS DO YOU ANTICIPATE FOR 2021 TO 2023?

A. We are expecting an average annual increase of two percent in internal labor costs from 2021 to 2023.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THE INCREASE IN INTERNAL LABOR COSTS FROM 2021 TO 2023?

A. The increase in internal labor costs from 2021 to 2023 budgets is primarily due to annual base pay increases for both bargaining and non-bargaining employees. These annual base pay increases and the historical trends for base pay increases are discussed more fully in the Direct Testimony of Ms. Lowenthal.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INCREASES IN INTERNAL LABOR COSTS.

A. The Transmission business unit closely monitors our overall headcount numbers, ensuring that any increases in headcount above the budgeted levels are prudent and fully reviewed. In addition, we closely monitor the amount of time spent on capital activities on a monthly basis as part of the overall monthly reporting to manage the amount of internal labor being charged to O&M.

2. *Contract Labor and Consulting*

Q. WHAT COSTS ARE INCLUDED IN THE TRANSMISSION O&M BUDGET FOR CONTRACT LABOR AND CONSULTING?

A. This category represents our use of contract labor and consultants, which allows the Company to increase and decrease its staffing levels as workloads require rather than bringing on more full-time staff. Using contract labor also allows use the ability to retain the services of experts, as needed, for specific tasks or project efforts. We believe utilizing contractors and consultants in this way is an efficient and cost-effective way to complete required work while ensuring the cost for the resources is only incurred during time it is needed.

Q. WHAT CHANGES IN CONTRACT LABOR AND CONSULTING COSTS DO YOU ANTICIPATE FOR 2021 TO 2023?

A. We are expecting an average decrease of three percent in contract labor and consulting costs for 2021 to 2023, as compared to the average of the 2017 to 2019 actual costs.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THIS DECREASE IN CONTRACT LABOR AND CONSULTING COSTS?

A. The decrease in contract labor and consulting costs is driven by productivity improvement initiatives, which have been implemented by the business. These efforts have resulted in improved scheduling and field productivity, resulting in more efficient and effective ways for transmission crews to spend their time, thus reducing the need for contractor support and the outsourcing of certain O&M activities.

Q. WHAT STEPS HAS TRANSMISSION TAKEN TO MINIMIZE CONTRACT LABOR COSTS?

A. While utilizing contractors and consultants can be a cost-effective method of managing labor costs on projects with variable workloads, the Transmission business unit continues to take steps to minimize the cost of contract labor and consulting costs. This includes increasing the reliance on workload planning to ensure the staffing levels, including both internal and external resources, are at the minimum required levels. Furthermore, the Transmission business unit utilizes strategic sourcing and the competitively bid Master Service Agreement program to obtain qualified and cost-effective contract labor. The Master Service Agreement program creates supply agreements with several preferred vendors to obtain bulk discounts and better service.

3. Employee Expenses

Q. WHAT COSTS ARE INCLUDED IN THE O&M BUDGET FOR EMPLOYEE EXPENSES?

A. This category represents expenses incurred by employees when traveling to remote locations to perform field work or traveling to required trainings, personal communication device expenses, and necessary (non-capital) safety equipment. Travel expenses incurred include per diem, mileage, hotel and airfare, travel meals, and other travel-related expenditures.

Q. WHAT CHANGES IN EMPLOYEE EXPENSE COSTS DO YOU ANTICIPATE FOR 2021 TO 2023?

A. We are expecting an average increase of 11 percent in employee expenses for 2021 to 2023, as compared to the average of the 2017 to 2019 actual costs. As discussed above, Transmission is planning to utilize more internal labor versus contract labor over the term of the multi-year rate plan. This increased use of internal labor means that there will also be an increase in associated employee expenses.

4. Fees

Q. WHAT FEES ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT BUDGET?

A. This category consists of fees we are required to pay to the NERC and MRO for the operation of the transmission system. As a regulated utility, the Company is required to pay fees for each of those organization's operating costs. It also includes professional and utility association dues, as well as land and railroad permits and license fees, and other similar fees necessary for the operation of our business.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THE INCREASE IN FEES FROM 2021 THROUGH 2023?

A. The increase in the fees cost category for 2021 through 2023 is primarily attributable to increases in regulatory fees. The Company forecasts its regulatory fees based on guidance from the regulatory bodies. Guidance from NERC and MRO suggested a per year increase of five percent for both organizations. Consistent with this guidance, the Company has budgeted an average increase of 11 percent for 2021 to 2023 as compared to the 2017 to 2019 actuals.

5. Materials

Q. WHAT MATERIALS ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT BUDGET?

A. This category consists primarily of consumables, hardware, and refurbished materials used in substation maintenance and repair operations. Additionally, tools, small equipment, and supporting supplies are included.

Q. WHAT CHANGES IN MATERIALS COSTS DO YOU ANTICIPATE FOR 2021 TO 2023 AS COMPARED TO 2019 ACTUALS?

A. We are expecting an average decrease of 23 percent in material costs for 2021 to 2023, as compared to the average of the 2017 to 2019 actual material costs.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THIS DECREASE IN MATERIAL COSTS?

A. This decrease in material costs is driven by policy reviews conducted by the Company that resulted in, among other things, changes in how the Company determined whether to repair versus replace certain assets. Specifically, this resulted in more replacement of assets as opposed to repairs, that then led to reductions in O&M expenditures for materials. In addition, the Transmission business unit continues to take advantage of the Master Service Agreement program, utilizing negotiated supply agreements with several preferred vendors to obtain bulk discounts and better service. We are also continuing to look for opportunities to optimize the sourcing for materials through efficiencies gained within the supply chain organization.

6. Miscellaneous

Q. WHAT COSTS ARE INCLUDED IN THE MISCELLANEOUS CATEGORY?

A. The miscellaneous category is primarily fleet costs. This category consists of costs for the internal fleet assets as directed to O&M accounts on an hourly basis by Transmission operations. This is an aggregate cost of all fleet equipment charged to Transmission O&M, including cars, trucks, construction equipment and trailers. In addition to fleet costs, the miscellaneous budget for 2021 to 2023 includes anticipated reductions in O&M as a result of productivity enhancements expected to be implemented by the Company.

Q. WHAT CHANGES IN MISCELLANEOUS COSTS DO YOU ANTICIPATE FOR 2021 TO 2023 AS COMPARED TO 2019 ACTUALS?

A. We are expecting an average decrease of 21 percent in miscellaneous costs for 2021 to 2023, as compared to the 2017 to 2019 average. Efforts to reduce per unit expense for transportation costs have resulted in decreased total fleet expenditures. Additionally, improvements in vehicle utilization tracking have resulted in fleet time and dollars being more accurately assigned to capital versus O&M projects, resulting in reduced O&M spend. Lastly, certain anticipated O&M reductions resulting from efficiency efforts initiated by the Company are captured in the miscellaneous cost category for the 2021 to 2023 budget.

V. THIRD-PARTY TRANSMISSION EXPENSES AND WHOLESALE TRANSMISSION REVENUES

A. Overview of the Transmission System in Minnesota and the Upper Midwest

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss the Company's third-party transmission revenues and expenses and the impact that pending FERC proceedings have on those revenues and expenses.

Q. GENERALLY SPEAKING, WHAT ARE THIRD-PARTY TRANSMISSION EXPENSES?

A. While NSP Transmission System loads and transmission facilities are primarily located within the NSP pricing zone, the NSP Companies serve loads in five other MISO pricing zones and a small load outside MISO. The NSP Companies also collect revenue for transmission facilities located in the GRE pricing zone, and several other utilities collect revenue for transmission facilities located in the NSP pricing zone.

As a result, the NSP Companies incur third-party transmission expenses to serve their native load customers, either in other zones or under Joint Pricing Zone (JPZ) arrangements developed to compensate other utilities for their facilities in the NSP pricing zone consistent with the MISO Transmission Owners Agreement. The NSP Companies also receive revenues for transmission and ancillary services provided to other utilities with load in pricing zones where NSP owns transmission assets or as otherwise provided under the MISO Tariff.

Q. WHAT IS THE RELATIONSHIP OF THIRD-PARTY TRANSMISSION EXPENSES AND WHOLESALE TRANSMISSION REVENUES TO THE COMPANY'S COST OF SERVICE?

A. Third-party transmission expenses and wholesale transmission revenues can either serve as a credit or debit to the Transmission business unit's O&M costs.

Q. PLEASE DESCRIBE THE HISTORICAL DEVELOPMENT OF THE TRANSMISSION FACILITIES IN MINNESOTA AND THE UPPER MIDWEST.

A. Electric utilities in Minnesota serve retail service areas that are spread throughout the state, sometimes non-contiguous to other parts of their retail service areas. The Company serves the Twin Cities, several major cities including St. Cloud, Mankato, and Winona, and about 400 other communities in Minnesota, while other utilities serve areas between the Company's territories. This is because electric utilities in Minnesota and the upper Midwest (investor-owned, cooperatives, and municipal utilities) have worked together for many years to develop a transmission network that will serve our respective native load customers. As a result, electric utilities in Minnesota and the region have highly interconnected transmission facilities that do not necessarily follow the patchwork of retail service area boundaries. This cooperation benefits our customers by providing the transmission infrastructure needed to serve our loads at a lower cost than if the Company and neighboring utilities each independently constructed facilities to reach their respective service area loads.

Q. HOW DOES THE HISTORY OF COOPERATION AFFECT THE COSTS TO MINNESOTA CUSTOMERS?

A. As designed and implemented, the jointly developed multi-owner transmission grid in Minnesota has resulted in less duplication of facilities and increased system efficiency. This has resulted in lower costs to customers throughout Minnesota.

Today, access to that multi-owner transmission grid is available under the MISO Tariff. Essentially, the Company receives revenue from other entities that use our transmission system and incurs an expense for using the transmission systems of other entities.

B. Third-Party Transmission Expenses and Revenues

Q. PLEASE EXPLAIN HOW THE WHOLESALE REVENUES AND THIRD-PARTY EXPENSES ARE RECOVERED.

A. The MISO Tariff recovers the costs of transmission facilities through rates established and billed by "pricing zones," which roughly match the boundaries of the local balancing authority areas operated by individual MISO member utilities. The local balancing authority areas closely resemble the control areas from the pre-MISO operational days. Control areas were used to designate transaction schedules and system dispatch responsibilities to specific utilities. When the transmission owners first began interconnecting, control area boundaries were established to roughly encompass a utility's transmission and generation assets. The concept of control areas (now local balancing authority areas) is still used for utility energy accounting purposes.

The concept of a pricing zone is that the "network loads" within the pricing zone, including a utility's retail native load customers, will bear the Annual Transmission Revenue Requirement (ATRR) associated with the transmission facilities in the zone on a load ratio share basis. The ATRR is calculated using the transmission cost of service rate formula set forth in the MISO Tariff for each transmission owner.

Q. HOW DOES THE BILLING WORK?

A. The Company is party to JPZ agreements for both the NSP pricing zone and the GRE pricing zone. Under these agreements, the transmission owning utilities are compensated for their facilities in the zone, and the load serving utilities are billed for their loads in the zone. Since the NSP Companies are both transmission owners and load serving entities in both pricing zones, the NSP Transmission System (1) receives revenues for its facilities in the NSP and GRE pricing zone and (2) incurs expenses for its loads in the NSP and GRE pricing zones.

Furthermore, as a MISO transmission owner, the NSP Companies collect third-party wholesale transmission service revenues for others' use of the NSP Transmission System under both the MISO Tariff and other wholesale transmission agreements. The NSP Transmission System also incurs transmission and/or ancillary expenses for its loads in other MISO pricing zones.

Q. PLEASE DESCRIBE THE TRANSMISSION THIRD-PARTY EXPENSES AND WHOLESALE REVENUES FOR 2021 TO 2023.

A. The NSP Transmission System (NSPM and NSPW combined) is operated as an integrated system and is treated as one under the relevant provisions of the MISO Tariff. Using third-party transmission is necessary to serve NSP Transmission System loads, including NSPM retail native loads in Minnesota, and thus the costs should be included in rates. However, those costs are offset by various transmission service revenues, thereby reducing total costs to NSPM customers in Minnesota. Table 13 summarizes the 2021 to 2023 budgets for MISO third-party transmission revenues and expenses and administrative charges for the total NSP Transmission System, compared to 2019 actual and 2020 forecast amounts.

Table 13

NSP System Third Party Transmission Expenses and Revenues ($000)

Description	2019 Actual	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Third Party Transmission Expenses					
JPZ Payments (NSP and GRE Zones)	$ 60,404	$ 48,985	$ 58,414	$ 60,066	$ 61,236
MISO Network Service, Point to Point, and Ancillary Services	$ 17,732	$ 22,421	$ 23,639	$ 24,335	$ 24,695
MISO Admin Charges (Sch 10)	$ 11,138	$ 10,802	$ 10,914	$ 11,601	$ 11,851
Other (Transmission Facilites/Other Native Load Deliveries, etc)	$ 239	$ 63	$ 210	$ 214	$ 218
TOTAL Third Party Expenses	$ 89,513	$ 82,272	$ 93,176	$ 96,215	$ 98,001
Wholesale Transmission Revenues	**2019 Actual**	**2020 Forecast**	**2021 Budget**	**2022 Budget**	**2023 Budget**
JPZ Revenues (NSP and GRE Zones)	$ 56,936	$ 48,047	$ 52,066	$ 55,598	$ 57,185
MISO Network Service	$ 25,163	$ 30,291	$ 30,595	$ 28,755	$ 29,618
MISO Point to Point	$ 7,923	$ 6,957	$ 6,353	$ 6,199	$ 6,205
GFAs	$ 418	$ 423	$ 423	$ 426	$ 427
Self-Funded Network Upgrades	$ -	$ -	$ 1,610	$ 4,710	$ 4,710
Other (Ancillary Services/LBA Services, etc)	$ 1,596	$ 1,766	$ 1,713	$ 1,731	$ 1,767
TOTAL Third Party Revenues	$ 92,036	$ 87,484	$ 92,760	$ 97,420	$ 99,913
Net Expense (Revenue)	$ (2,523)	$ (5,213)	$ 385	$ (1,236)	$ (1,944)

Since NSPM and NSPW operate the NSP Transmission System as an integrated system, the table above reflects NSP Transmission System revenues and expenses. The third-party transmission expenses and revenues are described in more detail later in my testimony and in Exhibit___(IRB-1), Schedules 4 and 5. The 2021 budget shows net expense which serves to increase to the Company's overall retail cost of service. Likewise, the 2022 and 2023 budget shows net revenues which serve to decrease the Company's overall retail cost of service.

Q. DO THE TRANSMISSION EXPENSES YOU DESCRIBE INCLUDE CHARGES UNDER MISO SCHEDULES 26 AND 26A TO RECOVER THE COSTS OF INVESTMENTS BY MISO MEMBERS RECOVERED THROUGH THE REGIONAL EXPANSION CRITERIA AND BENEFITS (RECB) TARIFF MECHANISM?

A. No. Schedules 26 and 26A provide for cost recovery of certain transmission projects. Schedule 26 recovers from MISO loads the costs of projects determined to be eligible for partial regional cost recovery as a "reliability" or "economic" project under the RECB mechanisms. Schedule 26A recovers from MISO loads the costs of projects determined to be eligible for full regional cost recovery as an MVP. The Company includes MISO Schedule 26 and 26A charges, as well as an offset for Schedule 26 and 26A revenues, in the TCR Rider.

Q. PLEASE DESCRIBE THE 2021, 2022, AND 2023 NSP TRANSMISSION SYSTEM THIRD-PARTY TRANSMISSION EXPENSES.

A. There are several types of third-party costs, which are summarized in Exhibit ___(IRB-1), Schedule 4. These are NSP Transmission System transmission costs necessary to serve NSP Transmission System loads, including NSP retail native loads in Minnesota, pursuant to rate schedules accepted for filing by FERC. My testimony provides the NSP Transmission System costs; Mr. Halama's cost of service reflects the portion allocated to the Minnesota jurisdiction.

- *JPZ Costs* – As I previously discussed, the NSP Transmission System incurs costs for serving its native loads within the NSP Joint Pricing Zone and in the GRE Joint Pricing Zone. The Company, GRE, Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, Northwestern Wisconsin Electric Company, Minnesota Municipal Power Agency, Missouri River Energy Services, East River Electric Power Cooperative and Rochester Public Utilities (collectively the "NSP Zone Transmission Owners") each own transmission facilities and serve loads in the NSP pricing zone. The 2021 to 2023 expense is for our use of the NSP Transmission Owners transmission facilities to serve the NSP Transmission System loads in the NSP pricing zone. The revenue reflects use of the NSP Transmission System facilities by other utilities to serve their respective loads in the NSP zone. The NSP Transmission System 2021, 2022, and 2023 net payment under the NSP-JPZ arrangement is forecast to be $7.6 million, $5.7 million, and $5.3 million, respectively, based on the JPZ expense and JPZ revenue summarized in Table 14 below.

Table 14
Joint Pricing Zone – NSP Zone
(Dollars in Millions)

	Revenue	Expense	Net Payment
2021	$47.1	$54.7	$7.6
2022	$50.5	$56.2	$5.7
2023	$52.0	$57.3	$5.3

Similarly, the NSP Transmission System has both native load and transmission facilities located in the GRE pricing zone, which is also a multi-utility zone. The Company pays GRE a net payment consisting of expense and revenue components: the expense of using other parties' facilities to serve the Company's native load, and the revenue paid by other parties for their use of NSP's facilities in the GRE zone. The NSP Transmission System 2021, 2022, and 2023 net receipt for the GRE JPZ is forecast to be $1.2 million, $1.3 million, and $1.3 million, respectively, based on the JPZ expense and JPZ revenue summarized in Table 15 below.

Table 15

Joint Pricing Zone - GRE Zone

(Dollars in Millions)

	Revenue	Expense	Net Receipt
2021	$4.9	$3.7	$1.2
2022	$5.1	$3.8	$1.3
2023	$5.2	$3.9	$1.3

Thus, the combined 2021, 2022, and 2023 impact of both the NSP JPZ and GRE JPZ is a net payment of $6.3 million, $4.5 million, and $4.0 million based on total expense and revenue summarized in Table 16 below and in Exhibit ___(IRB-1), Schedule 6.

Table 16

Joint Pricing Zone - NSP and GRE Zones

(Dollars in Millions)

	Revenue	Expense	Net Payment
2021	$52.1	$58.4	$6.3
2022	$55.6	$60.1	$4.5
2023	$57.2	$61.2	$4.0

- *Network Integration Transmission Service (NITS), Point to Point, and Ancillary Service Costs* – All NSP Transmission System native loads located within MISO are required to pay either a JPZ charge, as described above, or to purchase NITS under Schedule 9 of the MISO Tariff. Accordingly, the NSP Companies incur such charges with respect to their native loads in the Dairyland Power Cooperative, ITC Midwest, and Minnesota Power pricing zones. The NSP Companies' load in the Otter Tail Power pricing zone is treated as being in the NSP pricing zone for JPZ/NITS purposes. In addition to the base transmission (JPZ/NITS) charge, each load is also ascribed charges, as applicable, under the MISO Tariff for ancillary services, such as Schedule 1 – Scheduling, System Control and Dispatch Services, Schedule 2 – Reactive Supply and Voltage Control From Generation or Other Sources Service, and Schedule 33 – Blackstart Service. Finally, the Company serves a small native load in Berthold, North Dakota, that is connected to the Southwest Power Pool (SPP) system outside the MISO region. Under the MISO Tariff, the Company is required to purchase point-to-point (PTP) transmission service and associated ancillary services to export power supply resources from the MISO region. The NSP Transmission System 2021, 2022, and 2023 payments to MISO for these services are forecasted to be $23.6 million, $24.3 million, and $24.7 million, respectively.
- *MISO Administrative Charges* – MISO charges its transmission service customers, such as the Company, its Schedule 10 administrative charges to recover the costs of administering its Tariff and providing other transmission functions. The 2021, 2022, and 2023 charges of $10.9

million, $11.6 million, and $11.9 million, respectively, are based on MISO's forecast of its Schedule 10 rates.

- *Other Transmission Expense/Facility Charges.* The NSP Companies incur these costs to secure delivery rights for the integration of NSP Transmission System loads. This cost consists of payments to Dairyland Power Cooperative, Minnkota Power Cooperative, McLeod Cooperative Power Association, Redwood Electric Cooperative, Southwest Power Pool, and Stearns Electric Association for use of their respective facilities to enable the Company to serve certain native loads. The NSP Transmission System 2021, 2022, and 2023 payments to these entities are forecast to be $178,000; $183,000; and $186,000, respectively.

Q. WHAT ARE THE 2021, 2022, AND 2023 WHOLESALE TRANSMISSION REVENUES?

A. As shown in Table 13, the total NSP Transmission System 2021 test year wholesale revenues are estimated to be $92.7 million. The NSP Transmission System wholesale revenues for the 2022 and 2023 plan years are estimated to be $97.4 million and $99.9 million, respectively. Exhibit___(IRB-1), Schedule 5 provides more detailed information on the various transmission service revenues by type of service for 2019 and 2021, 2022, and 2023. The revenues from these wholesale services are reflected as revenue credits in the cost of service supported by Mr. Halama, thereby offsetting some of the third-party transmission expenses and reducing total costs to our Minnesota customers.

Q. HOW ARE THE WHOLESALE TRANSMISSION REVENUES KEPT ACCURATE AND CURRENT?

A. The NSP Companies update their MISO Attachment O ATRR every year. This update is required by the MISO Tariff and coordinated with MISO Tariff

Administration staff to reflect current year projected costs and the true-up of prior period costs and loads.

C. Pending FERC ROE Proceedings

Q. PLEASE EXPLAIN THE BACKGROUND OF THE PENDING FERC ROE PROCEEDINGS IN FERC DOCKET NOS. EL14-12 AND EL15-45.

A. On November 12, 2013, a group of industrial customers in the MISO region filed a complaint (FERC Docket No. EL14-12, or the "First Complaint") asking FERC to reduce the base rate of ROE used in the transmission formula rates of jurisdictional MISO transmission owners, including the NSP Companies, from 12.38 percent to 9.15 percent. On September 28, 2016, FERC issued Opinion 551, granting a 10.32 percent base rate ROE, effective November 12, 2013 to February 10, 2015 and prospectively from the date of the Order. Per Opinion 551, refunds were issued during the first half of 2017; however, multiple parties requested rehearing of Opinion 551, as discussed further below.

In February 2015, due to the impending expiration of the 15-month statutory limit on refund periods for complaints under section 206 of the Federal Power Act, a second Complaint (FERC Docket No. EL15-45, the "Second Complaint", or, together with the First Complaint, the "MISO ROE Complaints") was filed proposing to reduce the base ROE from 12.38 percent to 8.67 percent. The Second Complaint created a period of potential refunds from February 12, 2015 to May 11, 2016. In June 2016, based on the Opinion 531 methodology, an ALJ recommended a base ROE of 9.70 percent ("Second Complaint Initial Decision").[8] However, multiple parties filed exceptions to

[8] 155 FERC ¶ 63,030 (2016).

the Second Complaint Initial Decision, and the complaint continues to be subject to ongoing litigation, as discussed further below.

On April 14, 2017, the United States Court of Appeals, D.C. Circuit (D.C. Circuit Court) vacated and remanded Opinion 531, finding that FERC had not properly established that the existing ROE was unjust and unreasonable and also failed to adequately support the newly approved base ROE.[9] As Opinion 551 and the Second Complaint Initial Decision both cited Opinion 531 as the basis for the respective decisions, Opinion 531's vacatur also invalidated those decisions.

On November 21, 2019, FERC issued Opinion 569, an order on rehearing of Opinion 551 and FERC's initial order on the Second Complaint. Opinion 569 adopted a new ROE methodology and set a new base ROE of 9.88 percent, effective for the 15-month refund period from November 12, 2013, to February 11, 2015, and prospectively from September 28, 2016. Opinion 569 also dismissed the Second Complaint on the basis that the "existing rate" to be evaluated in that complaint was the 9.88 percent base ROE ordered in the First Complaint, which continued to be just and reasonable through the Second Complaint period. This dismissal drew a strongly-worded dissent from Commissioner Richard Glick, who, like the Complainant-Aligned Parties (CAPs), contended FERC should evaluate the Second Complaint not against the outcome of the First Complaint, but against the 12.38 percent base ROE inherent in rates paid by customers during the Second Complaint's refund period. Various parties requested rehearing of Opinion 569 on multiple grounds, including which models should be used to evaluate and set a new base

[9] *Emera Maine*, 854 F.3d at 22-23.

ROE, how the models should be applied, FERC's use of judgment, and the dismissal of the Second Complaint.

On May 21, 2020, FERC issued Opinion 569-A, which granted rehearing in part of Opinion 569, adopting a new ROE methodology which includes the risk premium model in addition to the DCF and CAPM, and established yet another new base ROE of 10.02 percent, effective for the First Complaint refund period (November 12, 2013 to February 11, 2015), and prospectively beginning September 28, 2016. The MISO TOs did not request rehearing but did appeal the decision to the D.C. Circuit Court, as discussed below.

On June 30, 2020, the D.C. Circuit Court issued an opinion in an unrelated case, *Allegheny Defense Project v. FERC,* finding FERC's practice of issuing "tolling orders," which previously had the effect of allowing FERC unlimited time to act on requests for rehearing, to be unlawful, and requiring FERC to act on requests for rehearing within 30 days.[10] On July 22, 2020, in response to the *Allegheny* decision, FERC issued an order denying the requests for rehearing as a matter of law, though FERC also indicated its intention to set aside its previous decision and issue a new order on rehearing at a future date.

Between June 1, 2020, and July 20, 2020, seven different groups, including the MISO TOs, filed petitions for review of Opinions 551, 569, and 569-A with the D.C. Circuit Court. On August 5, 2020, FERC filed a motion to hold the appeals in abeyance pending FERC's intended action on rehearing. Although it is uncertain what path this litigation will follow as it continues on rehearing at

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[10] *Allegheny Defense Project v. Federal Energy Regulatory Commission*, 964 F.3d 1, 18-19 (D.C. Cir. 2020).

FERC and through the appeals process in the courts, the one thing that seems certain is that it is far from over.

Q. WHAT IS THE NSP COMPANIES' MOST RECENT FERC-APPROVED ROE AT THIS TIME?

A. The most recent FERC order establishing a new base ROE for the NSP Companies is FERC Opinion 569-A, which set the base ROE at 10.02 percent. Although that Order remains subject to change from ongoing litigation, billed rates are currently based on that order and use a total ROE of 10.52 percent (10.02 percent base ROE, plus a 50 basis point incentive adder for RTO participation).

Q. DOES THE COMPANY HAVE CERTAINTY AT THIS POINT AS TO THE FINAL MISO ROE THAT WILL BE ADOPTED BY FERC?

A. Not at this time. As evidenced by the multiple requests for rehearing at FERC and appeals at the D.C. Circuit Court that are currently pending, there is still quite a bit of uncertainty as to the final ROE that will be adopted.

Q. WHAT HAS BEEN THE IMPACT OF THE MISO ROE COMPLAINTS ON NSPM'S FINANCIAL RESULTS FOR ITS MINNESOTA ELECTRIC JURISDICTION?

A. In previous Minnesota rate cases, the transmission revenue credit, which represents the pass-through to retail customers of revenues received for providing transmission service to other utilities, resulting in a reduction to the cost of service, has been calculated using the previously-effective MISO ROE of 12.38 percent. The Company has issued initial refunds for Opinion 569 for the time period from November 2013 through February 2015 and November 2019 through June 2020. As a result, the transmission revenues actually earned have fallen short of the level credited to Minnesota retail customers, causing financial loss to the Company that I discuss in more detail below.

Q. IS THERE A TRUE-UP MECHANISM TO PROTECT THE COMPANY AND RETAIL CUSTOMERS FROM THE FINANCIAL IMPACTS RESULTING FROM CHANGES TO THE MISO ROE DUE TO THE MULTIPLE PENDING FERC PROCEEDINGS?

A. No, at least not for transmission revenues credited to customers through base rates. Certain types of transmission revenue are credited to customers through the TCR Rider, which includes a true-up to ensure customers are credited with the actual amount, no more and no less, of the revenues received. However, for items included in base rates, there has been no true-up mechanism in place.

Q. CAN YOU QUANTIFY THE AMOUNT OF LOSSES EXPERIENCED BY THE COMPANY AS A RESULT OF THE DIFFERENCE BETWEEN THE ULTIMATE FERC ROE AND THE ROE USED TO CALCULATE THE MINNESOTA REVENUE CREDIT?

A. As I discussed previously, the ultimate outcome of the MISO ROE Complaints, including refunds for the time period since November 2013, is uncertain at this time. However, Table 17 below estimates the difference, on a Minnesota jurisdictional basis, between the level of the Company's transmission revenues included as a revenue credit in its previous rate cases, based on the 12.38 percent previously-effective base ROE and what that revenue credit would have been had the 10.02 percent base ROE from Opinion 569-A been known at the time those cases were filed.[11]

[11] An incentive adder of 50 basis points for RTO participation is applicable to periods on or after January 6, 2016; thus, for those periods, the 12.38 percent previous ROE is compared against a new ROE of 10.52 percent.

Table 17

Estimated Impact of ROE on Transmission Revenues

(State of MN Electric Jurisdiction)

Year	**12.38% vs. 10.02% base ROE** ***($000s)***
2013	$323
2014	$5,210
2015	$4,547
2016	$2,998
2017	$4,738
2018	$4,064
2019	$4,218
2020	$4,267
Total	**$30,365**

Thus, the Minnesota jurisdiction has received excess revenue credits of approximately $30.4 million from 2013 to 2020.

Q. WHAT DOES THE COMPANY RECOMMEND WITH RESPECT TO THE TRANSMISSION REVENUE CREDIT IN THIS CASE?

A. As discussed by Mr. Halama, the Company believes a determination at FERC on this matter should not impact the retail jurisdiction, and the cost of capital should be treated consistently across our rate base. Therefore, the transmission revenue credit has been calculated using the Company's most recently approved ROE of 9.06 percent as approved by the Commission in the Company's latest TCR Rider proceeding.[12] The Company further proposes to make an

[12] *In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factor*, Docket No. E002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS (Sept. 27, 2019).

adjustment as part of its compliance filings to reflect the final authorized ROE in this case.

Q. WHAT IS THE IMPACT OF A LOWER FERC AUTHORIZED ROE?

A. For the 2021 test year, a 10 basis point (0.1 percentage point) reduction in the FERC authorized ROE is estimated to result in a reduction in wholesale transmission revenues, net of third-party transmission expenses, of approximately $0.4 million. This amount excludes revenues and expenses under MISO Schedules 26 and 26A, which are excluded from base rates and instead included in the TCR Rider.

VI. TRANSMISSION SYSTEM LINE LOSS ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In its June 12, 2017 Order in our 2015 electric rate case, the Commission determined that the consideration of line losses—the amount of energy that is lost through the process of transmission and distribution—may further enhance the accuracy of the Class Cost of Service Study.[13] As a result, the Commission directed the Company in its next rate case to report on methods to conduct loss studies to measure line losses. The two general categories of losses on the Xcel Energy system are transmission losses and distribution losses. I will discuss the methods for measuring transmission losses, while Company witness Ms. Kelly A. Bloch discusses the methods for measuring distribution losses in her Direct Testimony.

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[13] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 49 (June 12, 2017).

Q. What are electric losses?

A. The Edison Electric Institute (EEI) defines electric losses as the general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system. Losses occur when energy is converted into waste heat in conductors and apparatus. Demand loss is power loss and is the normal quantity that is conveniently calculated because of the availability of equations and data. Demand loss is coincident when occurring at the time of system peak, and non-coincident when occurring at the time of equipment or subsystem peak. Class peak demand occurs at the time when that class's total peak is reached.

Q. How does the Company calculate losses on the transmission system?

A. The Company uses NSP hourly State Estimator data to calculate both the demand and energy losses on the NSP Transmission System.

Q. What is the State Estimator?

A. The State Estimator is basically an on-line power flow program that creates a complete complex voltage solution for the network model. The State Estimator solution is based on real-time measurements, scheduled load and generation, and dispatcher/operator entries. The State Estimator is performed several times per hour and provides a continuous snapshot of the transmission network.

Q. How does the State Estimator obtain the real-time measurements from the transmission system?

A. The State Estimator uses real-time data from the Company's Energy Management System (EMS). The EMS is an integrated set of computer hardware, software, and computer programs which aid Company transmission system operators in viewing, monitoring, and operating the transmission system. EMS receives real-time measurements from the field through telemetry. These real-time measurements are imperfect but redundant. This redundancy permits the State Estimator to determine an estimate for the voltage magnitude and angles for the observable portion of the network model which best matches the information given by the unfiltered measurements.

Q. ARE REAL-TIME MEASUREMENTS AVAILABLE FOR ALL OF PORTIONS OF THE TRANSMISSION SYSTEM?

A. No. Portions of the network that are not observable with real-time measurements. For those portions of the system, the State Estimator uses data from key nodal points on the system from which we have telemetry data from to determine the overall system status. That system status which includes load and generation values along with voltages and amperage, also reflects the overall losses on the system.

Q. HOW DOES THE STATE ESTIMATOR UTILIZE ALL OF THIS NETWORK DATA?

A. The State Estimator utilizes all of the collected data to create a real-time snapshot of the transmission network. This solved real-time network snapshot can be used for several applications including calculating transmission system losses.

Q. HOW CAN THIS REAL-TIME NETWORK BE USED TO CALCULATE TRANSMISSION SYSTEM LOSSES?

A. The State Estimator has the ability to provide over 8,000 states of data for calculating losses. The demand losses are the losses that occur on the NSP

Transmission System during the monthly peak hourly load. Energy losses will be the summation of all hourly losses in each month.

To calculate the required percentages, these losses will then be divided by NSP's local balancing authority (LBA) load. In the case of demand losses, the load will be the peak hour load while the energy loss will be the summation of MWh loads in the given month.

Not all the loads in NSP's LBA are NSP's native load. Loads from GRE and Dairyland Power Cooperative are within NSP's LBA. GRE is an electric cooperative based in Minnesota while Dairyland Power Cooperative is an electric cooperative based in Wisconsin. These loads also create losses on the transmission system and need to be added to NSP's load to obtain the correct loss percentages.

Q. WHAT ARE THE LIMITATIONS OF USING THE STATE ESTIMATOR CALCULATIONS OF TRANSMISSION SYSTEM LOSSES?

A. At the end of the day, any transmission system losses calculated by the State Estimator is an estimate based on collected data and may not necessarily reflect actual line losses at any given point in time. This is because the loss calculations created by the State Estimator rely on estimates for the portions of the system where we do not have real-time telemetry and are averaged into hourly time intervals.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Transmission organization constructs and maintains the transmission components for the NSP Transmission System that are necessary to enable the safe, reliable, and efficient delivery of energy from generating resources to customers. We anticipate completing $354.0 million of capital additions in 2021, $340.0 million in 2022, and $316.7 million in 2023. These capital additions include transmission projects for which we will seek rate recovery through the TCR Rider. These capital projects are needed to maintain the health of transmission facilities, meet reliability requirements, add capacity to support increasing amounts of new generation, interconnect new generators, and enable communication between our facilities.

We have budgeted $38.2 million for Transmission O&M in 2021, $38.7 million in 2022, and $40.4 million in 2023. The three-year average for these years ($39.1 million) is below the most recent three-year historical average (2017 to 2019) of $39.20 million.

These capital and O&M budgets are a reasonable representation of the work that Transmission will complete during the term of this MYRP and I recommend that the Commission approve Transmission's capital and O&M budget as presented in this rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications
Ian R. Benson

Current Responsibilities

My responsibilities include: supervising engineers in planning the electric transmission systems for the four Xcel Energy Inc. operating companies, NSPM, Northern States Power Company, a Wisconsin corporation (together the NSP Companies), Public Service Company of Colorado (PSCo), and Southwestern Public Service Company (SPS); overseeing the development of local and regional transmission system plans, including coordinated joint planning with the Midcontinent Independent Transmission System Operator, Inc. (MISO), and other utilities to ensure reliable transmission service; recommending the construction of such plans to Xcel Energy Inc. management and MISO; participating in and supporting MISO sponsored transmission service studies, generation interconnection studies, long range regional plan development, load service planning and other transmission planning activities required by MISO to perform its obligations under the MISO Tariff and the MISO Transmission Owner's Agreement; and providing technical support for regulatory aspects of transmission system planning activities and contract development for the NSP Companies, PSCo, and SPS.

Education:

Bachelor of Geological Engineering - 1984
University of Minnesota

Bachelor of Science, Mathematics – 1991
University of Minnesota

Master of Business Administration – 2010
University of St Thomas

Previous Employment (1991 to 2010):

Senior Engineer - Northern States Power Company (1991 – 1994)
Lead Sales Representative - Northern States Power Company (1994 – 1998)
Mid-Term Marketing Representative - Northern States Power Company (1998 – 1999)
Manager, Mid-Term Markets - Northern States Power Company (1999 – 2000)
Director, Origination - Xcel Energy Services Inc. (XES) (2000 – 2004)
Director, Transmission Access - XES (2004 – 2009)
Director, Transmission Investment Development - XES (2009 – 2010)
Director, Transmission Business Relations and Asset Management - XES (2010 – 2013)
Director, Transmission Planning and Business Relations - XES (2013 – 2016)
Area Vice President, Transmission Strategy and Planning – XES (2016 – present)

U.S. Navy

Active Duty: 1984 to 1989
Naval Reserve: 1989 to 2006

Transmission's Capital Additions: 2021-2023

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2021		2022		2023		
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	In-Service Date
NSPM Additions										
Asset Renewal	Major Line Rebuild	A.0000351.004	NSPM Major Line Rebuild,Line	0	0	0	0	63,858	46,567	12/31/2025
Asset Renewal	Major Line Rebuild	A.0000351.022	NSM0808 AIR RLK Rebuild Line	4,208	0	0	0	0	0	12/15/2021
Asset Renewal	Major Line Rebuild	A.0000351.026	NSM0730 - West Sioux Falls - Line 729	0	0	1,427	1,041	0	0	12/15/2022
Asset Renewal	Major Line Rebuild	A.0000351.030	NSM0752 Belgrade - Paynesville Rebuild	5,162	0	0	0	0	0	3/31/2021
Asset Renewal	Major Line Rebuild	A.0000351.033	NSPM 0795 Avon - Albany	0	0	5,352	3,902	0	0	1/15/2022
Asset Renewal	Major Line Rebuild	A.0000351.034	NSM0730 SOS - WSF Rebuild	0	0	1,399	1,020	0	0	12/15/2022
Asset Renewal	Major Line Rebuild	A.0000351.035	NSM0779 - Canisota Juntion - Salem,Line	1,866	0	0	0	0	0	12/15/2021
Asset Renewal	Major Line Rebuild	A.0000351.036	NSM0794 BLD DGC Rebuild	0	0	2,780	2,027	0	0	12/15/2022
Asset Renewal	Major Line Rebuild	A.0000351.037	NSM0703 FRM PKN Rebuild	0	0	884	645	0	0	12/15/2022
Asset Renewal	Major Line Rebuild	A.0000351.038	NSM0703 FRM NOF Rebuild	0	0	2,957	2,156	0	0	12/15/2022
Asset Renewal	Major Line Rebuild	A.0000351.039	NSM5401 MLK WAK Rebuild	0	0	3,826	2,790	0	0	12/15/2022
Asset Renewal	Major Line Rebuild	A.0000351.040	NSM0752 Belgrade - Paynesville PH2	0	0	2,624	1,913	0	0	12/15/2022
Asset Renewal	Major Line Refurbishment	A.0000498.004	NSPM Major Line Refurbishment	0	0	3,261	2,378	9,848	7,181	12/31/2025
Asset Renewal	Major Line Refurbishment	A.0000498.022	NSPM0815 BDS -WIL 115kV Refurb	2,666	1,944	0	0	0	0	6/30/2021
Asset Renewal	Major Line Refurbishment	A.0000498.024	NSM0752 Brooten Paynesville Refurb Line	1,599	1,166	0	0	0	0	6/15/2021
Asset Renewal	Major Line Refurbishment	A.0000498.025	NSM0734 West gate Excelsor Line	3,135	2,286	0	0	0	0	12/15/2021
Asset Renewal	Major Line Refurbishment	A.0000498.028	NSPM0857 BDS -NMC 115kV Refurb	2,689	1,961	0	0	0	0	6/30/2021
Asset Renewal	Major Line Refurbishment	A.0000498.031	NSM0746 Prairie Minnkota Refurb	482	351	0	0	0	0	6/15/2021
Asset Renewal	Major Line Refurbishment	A.0000498.037	NSM0735 CAR STB Refurb	0	0	180	131	0	0	12/15/2022
Asset Renewal	Major Line Refurbishment	A.0000498.038	NSM0735 CAR YAM Refurb	0	0	155	113	0	0	12/15/2022
Asset Renewal	Major Line Refurbishment	A.0000498.039	NSM0735 DLO STB Refurb	0	0	530	387	0	0	12/15/2022
Asset Renewal	Major Line Refurbishment	A.0000498.040	NSM0701 CRO to GFD Refurb	0	0	3,624	2,643	0	0	12/15/2022
Asset Renewal	Major Line Refurbishment	A.0000498.041	NSM5400 ALB-PAT-WAK Refurb	0	0	3,452	2,517	0	0	12/15/2022
Asset Renewal	Major Line Refurbishment	A.0000498.046	NSM0761 LAK ZUM Refurb	0	0	1,659	1,210	0	0	3/15/2022
Asset Renewal	Major Line Refurbishment	A.0000498.048	NSM0772 Prairie IC-Emerado Refurb	475	346	0	0	0	0	12/15/2021
Asset Renewal	Major Line Refurbishment	A.0000498.049	786 - Minnkota - Larimore, Line	793	578	0	0	0	0	12/15/2021
Asset Renewal	S&E - Line	A.0000177.043	NSPM S&E 69kV, Line	7,512	5,478	7,209	5,257	7,209	5,257	12/31/2025
Asset Renewal	S&E - Line	A.0000177.050	ND S&E B 69kV, Line	100	73	100	73	100	73	12/31/2025
Asset Renewal	S&E - Line	A.0000177.055	SD S&E B 69kV, Line	100	73	100	73	100	73	12/15/2025
Asset Renewal	S&E - Line	A.0000177.056	NSPM Priority Defects 69kV Line	1,001	730	1,001	730	1,001	730	12/30/2025
Asset Renewal	ELR Nuclear NSPM	A.0001014.001	NSPM - ELR - Nuclear	3,561	2,597	7,277	5,307	9,321	6,797	12/30/2024
Asset Renewal	Line ELR	A.0000504.025	NSPM T-Line ELR 2016 69kV, Line	3,417	2,492	3,519	2,566	4,320	3,150	12/15/2025
Asset Renewal	Line ELR	A.0000504.039	ND 69kV T-line ELR, Line	100	73	100	73	100	73	12/31/2025
Asset Renewal	Line ELR	A.0000504.043	SD 69kV T-line ELR, Line	100	73	100	73	100	73	12/31/2025
Asset Renewal	ELR - Relay	A.0000395.016	NSPM - 2016 - ELR - Relays	0	0	0	0	1,478	1,078	12/31/2025
Asset Renewal	ELR - Relay	A.0000395.029	NSPM - 2018 - ELR - Relays	182	132	0	0	0	0	11/15/2021
Asset Renewal	ELR - Relay	A.0000395.061	Airport Relaying - RLK	269	196	0	0	0	0	5/31/2021
Asset Renewal	ELR - Relay	A.0000395.062	Black Dog Relaying-BLL,BRV,CDV	0	0	0	0	765	558	5/15/2023
Asset Renewal	ELR - Relay	A.0000395.064	Elliot Park Relaying-MST,RIV	699	510	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000395.065	Fifth St Relaying - RIV	354	258	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000395.066	Ft Ridgely Relaying - WLM	0	0	0	0	353	257	12/15/2023
Asset Renewal	ELR - Relay	A.0000395.067	Koch Relaying - JNC	0	0	0	0	352	256	12/31/2023
Asset Renewal	ELR - Relay	A.0000395.068	Lincoln Co Relaying - CHC,CEN	539	393	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000395.069	Main St Relaying - ELP,RIV	800	583	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000395.071	Moore Lake Relaying - RIV	0	0	357	260	0	0	12/15/2022
Asset Renewal	ELR - Relay	A.0000395.072	Osseo Relaying - Bus1 TT	0	0	0	0	20	14	12/15/2023
Asset Renewal	ELR - Relay	A.0000395.073	Paynesville Relaying - WAK	0	0	0	0	20	14	11/15/2023
Asset Renewal	ELR - Relay	A.0000395.074	Prairie Relaying - NOR1,NOR2	0	0	0	0	820	598	12/15/2023
Asset Renewal	ELR - Relay	A.0000395.075	Riverside Relaying - MOL,TWL	0	0	701	511	0	0	12/15/2022
Asset Renewal	ELR - Relay	A.0000395.076	Riverside Relaying-ELP,FST,MST	1,028	749	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000395.077	Rogers Lake Relaying-AIR	256	187	0	0	0	0	2/15/2021

Transmission's Capital Additions: 2021-2023

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2021		2022		2023		
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	In-Service Date
NSPM Additions										
Asset Renewal	ELR - Relay	A.0000395.080	Tanners Lake Relaying - WDY	395	288	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000395.081	Twin Lakes Relaying - RIV	0	0	326	238	0	0	12/15/2022
Asset Renewal	ELR - Relay	A.0000395.082	Wakefield Relaying - PAT	0	0	0	0	20	14	11/30/2023
Asset Renewal	ELR - Relay	A.0000395.083	West Coon Rapids Relaying-ECK	0	0	0	0	20	14	11/30/2023
Asset Renewal	ELR - Relay	A.0000395.084	Wilmarth Relaying - FTR	0	0	0	0	536	391	12/15/2023
Asset Renewal	ELR - Relay	A.0000395.090	Cedarvale Replace Relaying to BDS	0	0	355	259	0	0	12/15/2022
Asset Renewal	ELR - Relay	A.0000395.096	Red Rock Relaying	328	239	0	0	0	0	5/15/2021
Asset Renewal	ELR - Breakers	A.0000394.009	NSPM ELR Breakers	0	0	0	0	1,478	1,078	12/31/2025
Asset Renewal	ELR - Breakers	A.0000394.016	Souris - Repalce Breaker 5T70	0	0	346	252	0	0	10/31/2022
Asset Renewal	ELR - Breakers	A.0000394.026	Fifth St-Replace Bkrs 5M760,5M765,5M770	1,307	953	0	0	0	0	12/15/2021
Asset Renewal	ELR - Breakers	A.0000394.027	Hugo-Replace Bkrs 5P196 & 5P197	0	0	871	635	0	0	12/15/2022
Asset Renewal	ELR - Breakers	A.0000394.028	Inver Grove-Replace 4P8,4P9,4P10	0	0	875	638	0	0	12/15/2022
Asset Renewal	ELR - Breakers	A.0000394.029	Minnesota Valley-Replace 69 kV & 115 kV	0	0	0	0	881	643	12/15/2023
Asset Renewal	ELR - Breakers	A.0000394.030	Prairie-Replace Bkrs 4G8 & 4G9	0	0	0	0	631	460	12/15/2023
Asset Renewal	ELR - Breakers	A.0000394.031	Arlington-Replace Bkrs 4S191,4S192,4S199	985	719	0	0	0	0	4/15/2021
Asset Renewal	ELR - Breakers	A.0000394.032	Rogers Lake-Replace Bkr 5P69	558	407	0	0	0	0	4/30/2021
Asset Renewal	ELR - Breakers	A.0000394.033	Rose Place-Replace Bkr 5P50	539	393	0	0	0	0	4/10/2021
Asset Renewal	ELR - Breakers	A.0000394.034	Wakefield-Replace Bkr 5N28	0	0	0	0	20	14	12/15/2023
Asset Renewal	ELR - Breakers	A.0000394.035	Winthrop-Replace Brk 4S54	1,636	1,193	0	0	0	0	5/30/2021
Asset Renewal	ELR - Breakers	A.0000394.036	Wilmarth-Replace Bkr 5S19	0	0	0	0	411	300	12/15/2023
Asset Renewal	ELR - Breakers	A.0000394.037	Westgate-Replace Bkrs 4M3 & 4M5	0	0	0	0	20	14	12/15/2023
Asset Renewal	W St Cloud - Black Oak	A.0000351.013	NSM0795 West St Cloud Millwood Tap	0	0	0	0	10,447	7,618	12/15/2023
Asset Renewal	0953 Replace OPGW	A.0001299.002	NSM0953 NOB SPK REPL OPGW MN	0	0	9,073	6,616	0	0	7/15/2022
Asset Renewal	ELR - Transformers	A.0000506.002	NSPM ELR Transformers	301	219	5,756	4,197	3,004	2,191	12/15/2025
Asset Renewal	Group 1 Switch Replacements	A.0000705.006	NSPM Switch Replacements, Line	0	0	491	358	1,576	1,149	12/31/2025
Asset Renewal	Group 1 Switch Replacements	A.0000705.019	NSM0737 Gleason Lake 4M58	0	0	0	0	228	167	12/15/2023
Asset Renewal	Group 1 Switch Replacements	A.0000705.020	NSM0782 Gleason Lake 4M17	0	0	0	0	228	167	12/15/2023
Asset Renewal	Group 1 Switch Replacements	A.0000705.021	NSM0721 Fairfax Muni Tap 450, 453	0	0	452	330	0	0	12/15/2022
Asset Renewal	Group 1 Switch Replacements	A.0000705.022	NSM0755 Bush Park Muni 4N41, 4N42, & 4N4	0	0	417	304	0	0	12/15/2022
Asset Renewal	Group 1 Switch Replacements	A.0000705.031	NSM0789 Wells Ck 4H21, 4H22, 4H23, Line	0	0	439	320	0	0	12/15/2022
Asset Renewal	Group 1 Switch Replacements	A.0000705.035	NSM0733 Reynolds Rpl SW 130 131	380	277	0	0	0	0	5/14/2021
Asset Renewal	Group 1 Switch Replacements	A.0000705.037	0733 Thonpson Rpl SW 120 121	388	283	0	0	0	0	6/14/2021
Asset Renewal	Group 1 Switch Replacements	A.0000705.041	NSPM GRE Switch Replacements 69kV, Line	98	72	98	72	98	72	12/15/2025
Asset Renewal	Group 1 Switch Replacements	A.0000705.048	NSM0719 Sleepy Eye City switch #290,291&	0	0	347	253	0	0	12/15/2022
Asset Renewal	Group 1 Switch Replacements	A.0000705.056	NSM0793 Villard 4N33 4N34	0	0	0	0	355	259	12/15/2023
Asset Renewal	Group 1 Switch Replacements	A.0000705.059	NSM0760 Frontenac SW 541 & 542	570	416	0	0	0	0	6/1/2021
Asset Renewal	Group 1 Switch Replacements	A.0000705.060	NSM0752 Brooten SW 686 687 Line	920	671	0	0	0	0	6/1/2021
Asset Renewal	Group 1 Switch Replacements	A.0000705.062	Averill Tap SW	20	15	0	0	0	0	4/15/2021
Asset Renewal	Transmission UAV Flights	A.0000855.001	NSPM Transmission UAV	6,210	4,529	0	0	0	0	10/30/2021
Asset Renewal	Tools Line Field Ops	A.0006059.085	Tools MN Sub	300	219	300	219	300	219	12/31/2025
Asset Renewal	Tools Line Field Ops	A.0006059.445	Tool Blanket MN, Line	147	107	154	113	162	118	12/31/2025
Asset Renewal	Tools Line Field Ops	A.0006059.452	Survey Group Tool B Line	60	44	50	36	50	36	12/31/2025
Asset Renewal	Tools Line Field Ops	A.0006059.453	Civil Dept Tool B Line	300	219	2,000	1,458	2,000	1,458	10/30/2025
Asset Renewal	Tools Line Field Ops	A.0006059.496	EPZ Mats MN	50	36	250	182	50	36	12/31/2025
Asset Renewal	S&E - Sub	A.0000585.008	ND S&E, Sub	64	47	64	47	64	47	12/31/2024
Asset Renewal	S&E - Sub	A.0000585.009	NSPM S&E, Sub	1,472	1,073	1,472	1,073	1,472	1,073	12/31/2025
Asset Renewal	S&E - Sub	A.0000585.013	SD S&E, Sub	64	47	64	47	64	47	12/31/2024
Asset Renewal	NSP Reloc B	A.0000276.026	NSPM Reloc B 69kV, Line	1,477	1,077	1,477	1,077	1,477	1,077	12/21/2025
Asset Renewal	NSP Reloc B	A.0000276.035	ND Reloc B 69kV Line	50	37	50	37	50	37	12/15/2025
Asset Renewal	NSP Reloc B	A.0000276.056	SD Reloc B 69kV, Line	50	37	50	37	50	37	12/15/2025
Asset Renewal	NSPM Metro Steel pole Rplmnt	A.0000743.004	NSPM Triple Ckt Pole Repl 2016	347	253	2,367	1,726	1,970	1,436	12/31/2025

Transmission's Capital Additions: 2021-2023

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2021		2022		2023		
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	In-Service Date
NSPM Additions										
Asset Renewal	NSPM Metro Steel pole Rplmnt	A.0000743.009	NSM0870 FST RIV Triple CKT Pole Rplmt	1	1	0	0	0	0	12/15/2021
Asset Renewal	Tools COM Substation	A.0006059.449	NSP COM Tool Sub	340	248	1,000	729	1,000	729	12/31/2025
Asset Renewal	Tools COM Substation	A.0006059.451	NSPM COM Tools (BU 8640)	135	98	135	98	140	102	12/31/2023
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.005	NSPM ELR - RTU,Comm	99	72	986	719	990	722	12/31/2024
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.025	AS King RTU Comm	52	38	0	0	0	0	5/15/2021
Asset Renewal	Unserviceable Brkr Rplmt Program	A.0000287.018	MN Unserviceable Breaker Replacement, Su	559	407	566	413	567	413	12/31/2024
Asset Renewal	Fault Recorders - NSPM	A.0000393.006	Eden Prairie Fault Recorder Comm	393	286	0	0	0	0	12/20/2021
Asset Renewal	Fault Recorders - NSPM	A.0000393.007	Kohlman Lake Fault Recorder Comm	462	337	0	0	0	0	12/20/2021
Asset Renewal	Fault Recorders - NSPM	A.0000393.008	Elm Creek - Install Fault Recorder Comm	420	306	0	0	0	0	11/30/2021
Asset Renewal	Fault Recorders - NSPM	A.0000393.009	Inver Hills - Install Fault Recorder Com	348	254	0	0	0	0	11/30/2021
Asset Renewal	Unserviceable - Relays - NSPM	A.0000751.003	MN Unserviceable Relay	492	359	491	358	493	359	12/31/2024
Asset Renewal	Hiawatha West	A.0001413.001	Hiawatha West TR2 Install	1,397	1,019	0	0	0	0	1/15/2021
Asset Renewal	Tools, Training Center	A.0006059.447	NSPM Training Center Tools	592	432	75	55	75	55	12/31/2025
Asset Renewal	Tools System Protection Comm Eng	A.0006059.087	NSPM Sys Protect Comm Eng Testing Eq	100	73	100	73	100	73	12/31/2025
Asset Renewal	Tools - Engineering	A.0006059.450	NSP Ops Engineering Tools	60	44	60	44	60	44	12/31/2025
Asset Renewal	Tools STAC	A.0001019.001	NSPM Tools STAC	12	9	12	9	12	9	12/31/2025
Asset Renewal	Tools STAC	A.0001019.003	NSPM STAC Tools	12	9	12	9	12	9	12/31/2025
Asset Renewal	NSP Line Capacity	A.0000233.005	Line Capacity-MN, Line	10	7	0	0	0	0	12/1/2021
Asset Renewal Total				**67,593**	**41,096**	**86,158**	**62,828**	**130,874**	**95,436**	
Reliability Requirement	TACT	A.0000943.007	2020 NSPM NERC TPL(MN-TACT)	4	3	4	3	4	3	12/31/2024
Reliability Requirement	TACT	A.0000943.008	2021 NSPM NERC TPL (MN-TACT)	1	1	8,179	5,964	5,092	3,713	12/31/2023
Reliability Requirement	TACT	A.0000943.010	Red Rock Bkr Replacement	35	26	0	0	0	0	5/15/2021
Reliability Requirement	TACT	A.0000943.011	Riverside Bkr Replacement	35	25	0	0	0	0	5/15/2021
Reliability Requirement	TACT	A.0000943.013	St Louis Park Bkr Replacement	1,952	1,424	0	0	0	0	5/31/2021
Reliability Requirement	TACT	A.0000943.014	West Coon Rapids Bkr Replacement	755	551	0	0	0	0	5/15/2021
Reliability Requirement	TACT	A.0000943.016	AS King Bkr Replacement	585	426	0	0	0	0	5/15/2021
Reliability Requirement	TACT	A.0000943.017	Black Dog Bkr Replacement	83	60	0	0	0	0	5/15/2021
Reliability Requirement	TACT	A.0000943.018	Chisago Bkr Replacement	200	146	0	0	0	0	5/15/2021
Reliability Requirement	TACT	A.0000943.019	Coon Creek Bkr Replacement	1,987	1,449	0	0	0	0	5/15/2021
Reliability Requirement	TACT	A.0000943.020	Jim Falls Bkr Replacement	11	8	0	0	0	0	3/15/2021
Reliability Requirement	TACT	A.0000943.021	Sheyenne Bkr Replacement	10	7	0	0	0	0	3/15/2021
Reliability Requirement	HIBTAC 500kV	A.0000901.001	HIBTAC 500kV Relocation Line	15,469	11,280	0	0	0	0	12/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.016	NSM5538 Galloping Mitigation Line	2,196	1,601	0	0	0	0	9/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.017	NSM5545 Galloping Mitigation Line	1,525	1,112	0	0	0	0	9/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.018	NSM5547 Galloping Mitigation Line MN	1,059	772	0	0	0	0	8/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.019	NSM5547 Galloping Mitigation Line SD	329	240	0	0	0	0	9/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.020	NSM5538 Galloping Mitigation Line SD	65	47	0	0	0	0	9/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.022	NSM5531 Galloping Mitigation Line	3,216	2,345	0	0	0	0	9/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.024	NSM 5537 Galloping Mitigation Line	2,237	1,631	0	0	0	0	9/15/2021
Reliability Requirement	DCP Great Plains	A.0010174.004	Great Plains 5503 Line	0	0	0	0	3,160	2,304	12/15/2023
Reliability Requirement	DCP Great Plains	A.0010174.005	Great Plains Sub TAM	0	0	0	0	3,293	2,401	12/15/2023
Reliability Requirement	Black Dog-Wilson 115kV uprates	A.0000155.002	Black Dog Wilson 115kV Uprates Sub	5,308	3,870	0	0	0	0	3/1/2021
Reliability Requirement	Long Lake-Baytown Ln #0801 Uprate	A.0001438.001	LN #0801 Baytown - Long Lake Reconductor	0	0	4,959	3,616	0	0	6/1/2022
Reliability Requirement	Wilmarth-TC Thru Flow Mitigation	A.0000385.001	Line 0717 GRI to CAR Rbld, Line	0	0	4,040	2,946	0	0	3/1/2022
Reliability Requirement	Magic City Extension	A.0001450.003	Line 0860 ROW	0	0	0	0	3,000	2,188	12/1/2023
Reliability Requirement	Hollydale Dist.115 kV	A.0000226.013	Holydale TR Expansion TAM	1,656	1,207	22	16	0	0	12/31/2021
Reliability Requirement	Hollydale Dist.115 kV	A.0000226.021	Line5409 In/Out at HOL	435	317	0	0	0	0	12/1/2021
Reliability Requirement	Raptor Distribution Substation	A.0010148.007	South Washington Sub In Out	642	468	0	0	0	0	5/15/2021
Reliability Requirement	Raptor Distribution Substation	A.0010148.008	South Washington Sub TAM	1,418	1,034	0	0	0	0	5/15/2021
Reliability Requirement	Falls Capacitor Bank	A.0001185.001	Falls 40MVAR Cap Bank Sub	0	0	1,941	1,415	0	0	6/1/2022

Transmission's Capital Additions: 2021-2023

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2021		2022		2023		
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	In-Service Date
NSPM Additions										
Reliability Requirement	Lincoln County Capacitor Bank	A.0001184.001	Lincoln Co 30MVAR Cap Bank Sub	1,649	1,202	0	0	0	0	6/1/2021
Reliability Requirement	Wilmarth/Mankato Energy Center Trans. Pr	A.0000660.001	ARL Main Bus Reconfig(USE), Sub	0	0	1,263	921	0	0	5/31/2022
Reliability Requirement	Wilmarth/Mankato Energy Center Trans. Pr	A.0000660.003	GRI Trans DE Switches Sub	380	277	0	0	0	0	4/1/2021
Reliability Requirement	0714:MDE(ITC)MDL(City)Tap Rbld	A.0000727.001	Line 714 rebuild, Line	0	0	1,606	1,171	0	0	12/1/2022
Reliability Requirement	Stockyards Sub	A.0000718.001	Stockyards DCP TR3, Sub	0	0	1,314	958	0	0	10/15/2022
Reliability Requirement	Stockyards Sub	A.0000718.002	0818/5529 Tap Relo, Line	0	0	139	101	0	0	10/15/2022
Reliability Requirement	Aldrich DCP	A.0000986.001	Aldrich DCP Upgrade Feeders, Sub	0	0	1,015	740	0	0	6/1/2022
Reliability Requirement	Forbes Substation SVC Retire	A.0001179.001	FBS Retire Forbes SVC	980	715	0	0	0	0	12/15/2020
Reliability Requirement	Prairie Substation Capbank Remove	A.0001178.001	Prairie Sub Remove 40 MVAR Capbank	850	620	0	0	0	0	4/15/2021
Reliability Requirement	Fair Park	A.0001424.001	Fair Park TR1 Feeder	752	548	0	0	0	0	4/15/2021
Reliability Requirement	Fair Park	A.0001424.002	Fair Park RTU Comm	42	31	0	0	0	0	4/15/2021
Reliability Requirement	Wilson Substation Conversion	A.0000390.001	Wilson Breaker and 1/2	470	343	0	0	0	0	12/28/2020
Reliability Requirement	Wilson Substation Conversion	A.0000390.013	WilSub Breaker and Half Comm	249	181	0	0	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.001	ASK-Repl/Add DFR shelves	194	141	0	0	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.002	BLL-Repl/Add DFR shelves	193	141	0	0	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.003	RRK-Repl/Add DFR shelves	102	75	0	0	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.004	TER-Repl/Add DFR shelves	102	75	0	0	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.005	WLM-Repl/Add DFR shelves	99	72	0	0	0	0	6/15/2021
Reliability Requirement	Cannon Falls Retaining Wall	A.0000725.001	(TBD)Cannon Falls Site Imprvmnt,Sub	328	239	0	0	0	0	12/15/2021
Reliability Requirement	Hatton Sub	A.0000744.001	DCP - Hatton TR, Line	0	0	0	0	153	111	10/31/2023
Reliability Requirement	Forbes Communication	A.0001179.003	Forbes Comm	107	78	0	0	0	0	5/15/2021
Reliability Requirement	Rosemount Sub	A.0000715.001	Rosemount TR2, Sub	59	43	0	0	0	0	12/15/2020
Reliability Requirement	Rosemount Sub	A.0000715.002	Rosemount TR2 Sub Comm	12	9	0	0	0	0	12/15/2020
Reliability Requirement Total				**47,780**	**34,842**	**24,481**	**17,852**	**14,701**	**10,720**	
Interconnection	SFNU MTEP18 NSPM	A.0001378.002	SNFU Development Pre Con	493	360	16,533	12,056	29,233	21,317	1/1/2026
Interconnection	J512/J569/J587/J590 HNA-SCO	A.0001412.001	J512/J569/J587/J590 Line0982 HNA-SCO	35,769	26,083	0	0	0	0	12/15/2021
Interconnection	IA Tariff Fund	A.0000076.002	IA Tariff Fund NSP	0	0	8,512	6,207	4,005	2,920	12/31/2025
Interconnection	J569 Rock County Sub	A.0001460.001	J569 RCY SUB - NU SELF FUND	1,378	1,005	0	0	0	0	9/1/2021
Interconnection	East River Wellington	A.0001387.001	East River Wellington Interconnection	1,229	896	0	0	0	0	6/30/2021
Interconnection	G621 Wind Int.	A.0000898.001	G621 Chanarambie Wind Interc Sub Direct	125	91	0	0	0	0	10/15/2021
Interconnection	G621 Wind Int.	A.0000898.002	G621 Chanarambie Wind Interc Sub Network	-2	-1	0	0	0	0	10/15/2021
Interconnection Total				**38,992**	**28,434**	**25,045**	**18,263**	**33,237**	**24,237**	
Physical Security and Resiliency	Physical Security	A.0000710.004	NSPM Physical Security Sub Infrstruc	12,551	9,153	14,899	10,865	15,232	11,107	12/31/2025
Physical Security and Resiliency	Physical Security	A.0000710.010	NSPM Physical Security Comm	5,547	4,045	3,670	2,677	4,525	3,300	12/30/2025
Physical Security and Resiliency	Physical Security	A.0000710.011	NSPM ND Physical Security Comm	65	48	453	330	0	0	9/30/2022
Physical Security and Resiliency	Physical Security	A.0000710.017	Arden Physical Security Comm	439	320	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.019	Fieldon Physical Security Comm	1	0	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.020	Merriam Park Physical Security Comm	0	0	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.021	Moore lake Physical Security Comm	0	0	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.026	Rose Place Physical Security Infrastr	0	0	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.030	Arden Hills Physical Security Infrastr	1,401	1,022	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.031	Fieldon Physical Security Infrastr	0	0	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.033	Moore Lake Physical Security Infrastr	0	0	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.044	Wilmarth Physical Security Infrasr	1,346	981	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.045	Crandall Physical Security Infrastr	932	0	0	0	0	0	12/15/2021
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.001	NERC 754 Protection Sys MN,Sub	0	0	10,608	7,736	4,253	3,101	10/30/2024
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.003	Prairie Island NERC Order 754 Upgrade	1,097	800	0	0	0	0	9/15/2021
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.004	Monticello NERC Order 754 Upgrade	418	304	0	0	0	0	3/30/2021
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.008	Forbes 500kV NERC Order 754	190	138	0	0	0	0	12/15/2021

Transmission's Capital Additions: 2021-2023

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2021		2022		2023		
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	NSPM (Total Company)	State of MN Elec. JUR	In-Service Date
NSPM Additions										
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.010	Parkers Lake 345kV NERC Order 754	279	203	0	0	0	0	3/30/2021
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.011	Blue Lake 345kV NERC Order 754 Upgrade	227	165	0	0	0	0	12/15/2021
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.016	Chisago 345kV NERC Order 754	304	222	0	0	0	0	12/15/2021
Physical Security and Resiliency	OT Cyber Security NSPM	A.0001456.001	Monitoring Logging RTCA MN	0	0	3,156	2,302	1,866	1,361	10/31/2024
Physical Security and Resiliency	OT Cyber Security NSPM	A.0001456.002	Asset Management Software MN	0	0	843	615	1,028	750	12/31/2025
Physical Security and Resiliency	NSPM Physical Security	A.0000745.002	NSPM SD Physical Security Infrsturc	0	0	2,893	2,110	0	0	12/15/2022
Physical Security and Resiliency	NSPM Physical Security	A.0000745.004	NSPM (ND) Physical Security Infrsturc	0	0	2,614	1,906	0	0	12/15/2022
Physical Security and Resiliency	Geo Mag Dist (GMD)	A.0000752.006	NSPM Geo Mag Dist (GMD)	101	74	1,010	736	2,020	1,473	10/31/2024
Physical Security and Resiliency	NSPM Electro Mag Pulse (EMP)	A.0000957.005	NSPM Electro Mag Pulse (EMP)	0	0	198	145	0	0	12/31/2022
Physical Security and Resiliency Total				**24,897**	**17,476**	**40,347**	**29,421**	**28,923**	**21,092**	
Regional Expansion	Huntley Wilmarth 345*	A.0000835.001	Huntley Wilmarth Precertification	0	0	0	0	0	0	12/30/2021
Regional Expansion	Huntley Wilmarth 345*	A.0000835.003	Huntley Wilmarth 345 ROW N/S	1,456	1,062	63	46	0	0	12/31/2021
Regional Expansion	Huntley Wilmarth 345*	A.0000835.004	Huntley Wilmarth 345 Line N/S	61,313	44,711	4,149	3,026	0	0	12/31/2021
Regional Expansion	Huntley Wilmarth 345*	A.0000835.005	Wilmarth 345 Sub Expansion for HW Line	3,260	2,378	90	66	0	0	12/15/2021
Regional Expansion	Huntley Wilmarth 345*	A.0000835.006	0982 WLM-Crandall HW 2nd Circuit N/S	7,204	5,253	0	0	0	0	5/30/2021
Regional Expansion	Google Data Center	A.0001365.001	0827 SCL SNL	1,391	1,014	0	0	0	0	9/15/2021
Regional Expansion	Google Data Center	A.0001365.002	0827 SNL LIB	0	0	518	378	0	0	7/15/2022
Regional Expansion	Google Data Center	A.0001365.003	5573 SNL SHC	0	0	518	378	0	0	7/15/2022
Regional Expansion	Google Data Center	A.0001365.004	5574 SNL SHC	0	0	518	378	0	0	7/15/2022
Regional Expansion	Google Data Center	A.0001365.005	Snuffys Landing Sub	0	0	12,274	8,950	0	0	7/15/2022
Regional Expansion Total				**74,624**	**54,417**	**18,130**	**13,221**	**0**	**0**	
Communications Infrastructure	Comm Network Program	A.0001320.007	NSPM Comm Network Program Comm	3,940	2,873	15,859	11,565	25,516	18,607	12/15/2025
Communications Infrastructure	Comm Network Program	A.0001320.017	AS King - Private Comm Network	0	0	354	258	0	0	1/15/2022
Communications Infrastructure	Comm Network Program	A.0001320.018	Black Dog - Private Comm Network	0	0	353	258	0	0	1/15/2022
Communications Infrastructure	Comm Network Program	A.0001320.019	Prairie Island - Private Comm Network	0	0	353	258	0	0	1/15/2022
Communications Infrastructure	Comm Network Program	A.0001320.020	Rosemount - Private Comm Network	0	0	353	257	0	0	1/15/2022
Communications Infrastructure	NSPM COMM Circuit Upgrades	A.0001357.002	NSPM 2017 COMM Circuit Upgrades	170	124	170	124	170	124	12/31/2025
Communication Infrastructure Total				**4,110**	**2,997**	**17,443**	**12,720**	**25,686**	**18,731**	
NSPM Total				**257,995**	**179,261**	**211,604**	**154,306**	**233,422**	**170,216**	

**Those projects that will be recovered through the Transmission Cost Recovery Rider*

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2021		2022		2023		
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPW (Total Company)	State of MN Elec. JUR	NSPW (Total Company)	State of MN Elec. JUR	NSPW (Total Company)	State of MN Elec. JUR	In-Service Date
NSPW Additions										
Asset Renewal	Major Line Rebuild	A.0000689.022	W3477 RBL STR 368 69Kv Rebuild Line	4,868	3,550	0	0	0	0	4/30/2021
Asset Renewal	Major Line Rebuild	A.0000689.023	W3477 STR 368 MFD 69kV Rebuild Line	0	0	4,520	3,296	0	0	5/1/2022
Asset Renewal	Major Line Rebuild	A.0000689.030	W3604 Port Wing Rebuild for DIST Sub	0	0	0	0	4,724	3,445	6/1/2023
Asset Renewal	Major Line Rebuild	A.0000689.034	W3408 Mondovi to GMN Tap	2,204	1,607	0	0	0	0	6/15/2021
Asset Renewal	Major Line Rebuild	A.0000689.035	W3408 GMN Tap to STR 563	0	0	3,107	2,266	0	0	5/15/2022
Asset Renewal	Major Line Rebuild	A.0000689.036	W3408 STR 563 to Nelson	0	0	0	0	3,421	2,495	5/15/2023
Asset Renewal	Major Line Rebuild	A.0000689.043	W3321 STR 140 to Phillips Tap Rebuild	0	0	4,059	2,960	0	0	1/15/2022
Asset Renewal	Major Line Rebuild	A.0000689.045	W3320 Osprey to STR 54 Rebuild	3,966	2,892	0	0	0	0	4/27/2021
Asset Renewal	Major Line Rebuild	A.0000689.047	W3320 STR 54 to Hawkins Rebuild	0	0	3,418	2,492	0	0	4/15/2022
Asset Renewal	Major Line Rebuild	A.0000689.049	W3408 Naples to Mondovi	2,483	1,811	0	0	0	0	4/5/2021
Asset Renewal	Major Line Rebuild	A.0000689.050	W3320 Hawkins to Catawba Rebuild	0	0	0	0	3,447	2,514	4/15/2023
Asset Renewal	Major Line Refurbishment	A.0000583.003	NSPW Major Line Refurbishment,Line	0	0	2,675	1,950	2,982	2,175	12/31/2025
Asset Renewal	Major Line Refurbishment	A.0000583.047	NSW3454 Refurbishment Str 98 to 118	291	212	0	0	0	0	6/1/2021
Asset Renewal	Major Line Refurbishment	A.0000583.052	W3304 Hay River to Pine Lake	2,678	1,953	0	0	0	0	7/15/2021
Asset Renewal	Major Line Refurbishment	A.0000583.053	W3304 Pine Lake to Three Lakes Rebuild	0	0	3,270	2,384	0	0	12/15/2022
Asset Renewal	Major Line Refurbishment	A.0000583.054	W3304 Three Lakes to Willow River Tap	0	0	0	0	1,986	1,448	12/15/2023
Asset Renewal	Major Line Refurbishment	A.0000583.056	W3213 RCD WHT Repl Strs 53 to 206	0	0	6,704	4,889	0	0	1/15/2022
Asset Renewal	Major Line Refurbishment	A.0000583.057	W3213 RCD WHT REPL STRS PH 2	6,565	4,787	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000503.002	NSPW - 2016 - ELR - Relays	0	0	4,257	3,104	1,962	1,431	12/31/2025
Asset Renewal	ELR - Relay	A.0000503.023	Cedar Falls-Relaying CLL,ECL,MEN,RCD	1,338	976	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000503.024	Cotton School-Relaying ALC,SPL,SEV,Bus1	1,327	968	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000503.025	Flambeau-Relaying PFA,PFA	0	0	0	0	602	439	12/15/2023
Asset Renewal	ELR - Relay	A.0000503.027	Hurley-Rpl Sync Cond Relays and Cntrls	579	422	0	0	0	0	2/15/2021
Asset Renewal	ELR - Relay	A.0000503.028	Jackson Co-Relaying ALC,HAF,MLE	0	0	0	0	904	659	12/15/2023
Asset Renewal	ELR - Relay	A.0000503.029	Jim Falls-Relaying RCL,HYD,HLC	1,127	822	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000503.030	Park Falls-Relaying FLB1,FLB2	0	0	0	0	625	456	12/15/2023
Asset Renewal	ELR - Relay	A.0000503.033	Seven Mile-Relaying ECL,ELS,LON,CTS,SEM	1,272	928	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000503.035	Spokesville-Relaying CTS,TCN,TCN	886	646	0	0	0	0	5/31/2021
Asset Renewal	ELR - Relay	A.0000503.036	T-Corners-Relaying SPE,WIT,MFD,SPL	1,387	1,011	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000503.037	Tremval-Relaying ALC,IDP,MLE	1,008	735	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay	A.0000503.040	Crystal Cave Relaying	326	238	0	0	0	0	5/15/2021
Asset Renewal	ELR - Relay	A.0000503.041	River Falls Relaying	309	225	0	0	0	0	5/15/2021
Asset Renewal	ELR - Transformers	A.0000398.002	NSPW ELR Transformers	101	74	2,994	2,183	4,419	3,223	12/15/2024
Asset Renewal	ELR - Transformers	A.0000398.006	ELR - ECL TR10 Replacement	0	0	6,383	4,654	0	0	2/15/2022
Asset Renewal	ELR - Breakers	A.0000397.010	NSPW - 2016 - ELR - Breakers	0	0	3,753	2,736	2,751	2,006	12/31/2025
Asset Renewal	ELR - Breakers	A.0000397.020	Flambeau-Replace Bkrs 3R132,3R133,3R254	0	0	0	0	620	452	12/15/2023
Asset Renewal	ELR - Breakers	A.0000397.022	Jackson Co-Replace Bkrs 4L6,4L7,4L8,4L9	0	0	0	0	1,222	891	12/15/2023
Asset Renewal	ELR - Breakers	A.0000397.023	Lacrosse-Replace Bkrs 4L44,4L45	580	423	0	0	0	0	12/15/2021
Asset Renewal	ELR - Breakers	A.0000397.024	Lacrosse-Replace Bkrs 6L4,6L5,6L7	1,539	1,122	0	0	0	0	2/15/2021
Asset Renewal	ELR - Breakers	A.0000397.025	Menomonie-Replace Bkrs 4E63,4E64	0	0	0	0	20	14	11/30/2023
Asset Renewal	ELR - Breakers	A.0000397.026	Monroe Co-Replace Bkrs 4L76,4L77	0	0	0	0	20	14	11/30/2023
Asset Renewal	ELR - Breakers	A.0000397.027	Marshland-Replace Bkrs	1,087	792	0	0	0	0	11/15/2021
Asset Renewal	ELR - Breakers	A.0000397.029	Prentice-Replace Bkr 4R6	291	212	0	0	0	0	3/15/2021
Asset Renewal	ELR - Breakers	A.0000397.031	T-Corners-Replace Bkr 4E22	400	292	0	0	0	0	5/31/2021
Asset Renewal	ELR - Breakers	A.0000397.032	Cumberland-Rpl Bkr 4R84	156	114	0	0	0	0	12/15/2021
Asset Renewal	ELR - Breakers	A.0000397.034	Bayfront Replace Breakers 5R42 & 5R47	1,037	756	0	0	0	0	1/15/2021
Asset Renewal	S&E - Line	A.0000495.021	NSPW S&E 69kV, Line	1,402	1,022	3,404	2,482	1,402	1,022	12/31/2025
Asset Renewal	S&E - Line	A.0000495.024	MI S&E 34.5kV, Line	50	37	50	37	50	37	12/15/2025
Asset Renewal	S&E - Line	A.0000495.026	NSPW Priority Defects 69kV Line	2,553	1,862	1,802	1,314	1,552	1,132	12/15/2025
Asset Renewal	W3203 Briggs-LaCrosse Upgrade	A.0002030.001	W3203 Briggs Lacrosse Rlbd Line	0	0	0	0	11,194	8,163	5/15/2023
Asset Renewal	W3203 Briggs-LaCrosse Upgrade	A.0002030.002	W3203 Briggs Lacrosse Rebuild	0	0	9	7	0	0	10/31/2022
Asset Renewal	W3205 LaCrosse-Coulee	A.0000689.024	W3205 LaCrosse Coulee Rebuild	9,775	7,128	0	0	0	0	1/15/2021
Asset Renewal	Line ELR	A.0000327.017	NSPW 69kV Line ELR 2016	2,860	2,086	2,264	1,651	2,462	1,795	12/15/2025
Asset Renewal	Line ELR	A.0000327.022	MI 34.5kV TLine ELR Line	50	37	50	37	50	37	12/15/2025
Asset Renewal	Transmission UAV Flights	A.0000855.002	NSPW Transmission UAV	4,401	3,210	0	0	0	0	10/15/2021
Asset Renewal	W3432 LaCrosse-Coulee 69 kV rebuild	A.0001239.001	W3432 LaCrosse-Coulee 69 kV rebuild	0	0	4,322	3,152	0	0	12/15/2022

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	WBS Level 2 #	Description	2021 NSPW (Total Company)	2021 State of MN Elec. JUR	2022 NSPW (Total Company)	2022 State of MN Elec. JUR	2023 NSPW (Total Company)	2023 State of MN Elec. JUR	In-Service Date
NSPW Additions										
Asset Renewal	Group 1 Switch Replacements	A.0000444.005	NSPW Switch Rplmts, Line	1,083	790	1,083	789	1,085	791	12/31/2025
Asset Renewal	Group 1 Switch Replacements	A.0000444.045	W3408 Naples Replace SW	433	316	0	0	0	0	3/31/2021
Asset Renewal	Group 1 Switch Replacements	A.0000444.052	W3612 DPC Butternut SW	0	0	0	0	0	0	6/1/2021
Asset Renewal	S&E - Sub	A.0000075.008	MI S&E, Sub	49	36	49	36	49	36	12/31/2024
Asset Renewal	S&E - Sub	A.0000075.009	NSPW S&E, Sub	1,177	859	1,177	859	1,177	859	12/31/2025
Asset Renewal	RTU - EMS Upgrade - NSPW	A.0000423.003	NSPW ELR - RTU,Comm	984	718	981	715	981	716	12/31/2024
Asset Renewal	RTU - EMS Upgrade - NSPW	A.0000423.011	LaCrosse RTU Comm	29	21	0	0	0	0	2/15/2021
Asset Renewal	Unserviceable - Relays - NSPW	A.0000396.003	WI Unserviceable Relay	493	359	492	359	491	358	12/31/2025
Asset Renewal	Unserviceable Brkr Rplmt Program	A.0000287.014	Unserviceable Breaker Replmnts, Sub MI	467	341	468	341	467	341	12/31/2025
Asset Renewal	NSPW Reloc B	A.0000496.022	MI Reloc B 34.5kV Line	50	37	50	37	50	37	12/15/2025
Asset Renewal	NSPW Reloc B	A.0000496.024	NSPW Reloc B 69kV Line	384	280	384	280	384	280	12/15/2025
Asset Renewal	Tools COM Substation	A.0006059.431	NSPW Com Tool	385	281	400	292	220	160	12/31/2025
Asset Renewal	Tools Line Field Ops	A.0006059.430	Tool Blanket WI, Line	74	54	77	56	81	59	12/31/2025
Asset Renewal	Tools Line Field Ops	A.0006059.497	EPZ Mats NSPW	50	36	50	36	50	36	12/31/2025
Asset Renewal	Tools STAC	A.0001019.004	NSPW STAC Tools	12	9	12	9	12	9	12/31/2025
Asset Renewal	Cable Sub	A.0001248.004	W3470 Reterm at CAB DCP	26	19	0	0	0	0	12/31/2020
Asset Renewal Total				**64,592**	**47,101**	**62,264**	**45,404**	**51,464**	**37,529**	
Reliability Requirement	Bayfield Loop	A.0000193.006	Bayfield Second Circuit-PKC TAM	0	0	4,627	3,374	40	29	11/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.007	Bayfield Second Circuit-FSC TAM	0	0	6,153	4,487	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.008	Bayfield Second Circuit-W3602 Reterm	0	0	196	143	5	4	11/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.009	Bayfield Second Circuit-W3603 Rebld	0	0	11,735	8,557	2,310	1,684	11/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.010	Bayfield Second Circuit-W3604 Reterm	0	0	196	143	5	4	11/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.011	Bayfield Second Circuit-BFT-STS Reterm	0	0	655	477	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.012	Bayfield Second Circ FSC-Tie Switch	0	0	1,280	933	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.013	Bayfield Second Circ Tie Switch PKC	0	0	1,240	904	20	15	11/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.014	Bayfield Second Circ W3601 Rebuild	0	0	14,587	10,637	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.015	Bayfield Second Circ-W3603 ROW	123	90	0	0	0	0	4/15/2021
Reliability Requirement	Bayfield Loop	A.0000193.016	Bayfield Second Circ-W3604 ROW	0	0	55	40	0	0	5/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.017	Bayfield Second Circ-W3602 ROW	0	0	55	40	0	0	5/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.018	Bayfield Second Circ-W3601 ROW	120	87	0	0	0	0	4/15/2021
Reliability Requirement	Bayfield Loop	A.0000193.019	Bayfield Second Circ-PKC Comm	0	0	152	111	0	0	11/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.020	Bayfield Second Circ-FSC Comm	0	0	152	111	0	0	2/15/2022
Reliability Requirement	Hurley Norrie 115kV	A.0001169.001	Hurley - Norrie 115kV	0	0	0	0	1,944	1,417	12/15/2023
Reliability Requirement	Hurley Norrie 115kV	A.0001169.002	Hur NRR 115kV MI 1.2 Miles	0	0	0	0	1,388	1,012	12/15/2023
Reliability Requirement	Hurley Norrie 115kV	A.0001169.003	NRR 115kV Yard Improvements	0	0	0	0	1,276	931	12/15/2023
Reliability Requirement	Hurley Norrie 115kV	A.0001169.004	HUR 115kV Yard Improvements	0	0	0	0	4,059	2,960	12/15/2023
Reliability Requirement	DCP Elmwood Substation	A.0010163.003	DCP Elmwood Substation	0	0	4,274	3,116	0	0	2/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.004	W3466 In Out at ELM Sub	0	0	91	66	0	0	2/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.005	W3415 Reterm to ELM Sub	0	0	1,137	829	0	0	2/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.006	W3466 MEN to ELM Sub	0	0	408	297	0	0	2/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.007	W3466 RLM to ELM Sub	0	0	408	297	0	0	2/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.008	DCP Elmwood Substation Land	0	0	0	0	0	0	11/15/2020
Reliability Requirement	DCP Elmwood Substation	A.0010163.009	Elmwood Substation 69kV Sub COMM	130	94	0	0	0	0	12/15/2021
Reliability Requirement	Twin Town Area Upgrades	A.0001159.002	Turtle Lake - Almena Line	5,599	4,083	0	0	0	0	9/15/2021
Reliability Requirement	Twin Town Area Upgrades	A.0001159.003	Turtle Lake Cap Bank Addition	569	415	0	0	0	0	6/15/2021
Reliability Requirement	Twin Town Area Upgrades	A.0001159.004	Turtle Lake Comm	208	152	0	0	0	0	3/15/2021
Reliability Requirement	Bayfront to Ironwood 88 kV	A.0000567.006	W3351 BFT - IRW ROW	2,250	1,641	1,750	1,276	0	0	12/15/2022
Reliability Requirement	Bayfront to Ironwood 88 kV	A.0000567.009	BFT IRW Permit Line SAP	600	438	0	0	0	0	12/31/2021
Reliability Requirement	Install Turtle Lake Area Substation	A.0001395.003	W3429 Pine Street to Lake Camelia	597	435	0	0	0	0	6/15/2021
Reliability Requirement	Install Turtle Lake Area Substation	A.0001395.004	W3429 Pine Street to Twin Town	0	0	0	0	350	256	12/15/2023
Reliability Requirement	Install Turtle Lake Area Substation	A.0001395.005	SUB Install Turtle Lake Area Sub DCP	868	633	0	0	0	0	6/15/2021
Reliability Requirement	Bayfront to Ironwood Bad River Res ROW	A.0001193.001	W3351 Bad River Res ROW	1,693	1,235	0	0	0	0	2/1/2021
Reliability Requirement	Western WI / E. Metro Upgrade	A.0001437.002	Willow River Sub 20 MVAR CAP	0	0	0	0	1,420	1,035	5/30/2023
Reliability Requirement	NSPW Galloping Conductors	A.0000762.001	NSPW 2019 Galloping Mitigation	1,383	1,009	0	0	0	0	3/31/2021
Reliability Requirement	Rest Lake-Presque Isle	A.0001198.001	Rest Lake Presque Isle ROW	100	73	150	109	400	292	4/15/2024

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	WBS Level 2 #	Description	Addition Amount ($000s) 2021 NSPW (Total Company)	2021 State of MN Elec. JUR	2022 NSPW (Total Company)	2022 State of MN Elec. JUR	2023 NSPW (Total Company)	2023 State of MN Elec. JUR	In-Service Date
NSPW Additions										
Reliability Requirement	FIN Reinforce TR1	A.0001415.001	FIN Reinforce TR1 DCP	529	385	0	0	0	0	5/15/2021
Reliability Requirement	FIN Reinforce TR1	A.0001415.002	FIN Reinforce TR1 Comm DCP	23	16	0	0	0	0	5/15/2021
Reliability Requirement	TACT	A.0000943.022	Jim Falls Bkr Replacement	237	173	0	0	0	0	5/15/2021
Reliability Requirement	ROW by Permit	A.0000879.002	NSPW USDA F S Ottawa MI 22 26 ROW	0	0	80	58	0	0	1/15/2022
Regional Expansion	DCP Kinnickinnic	A.0001247.001	W3426 Reterm at Kin DCP	0	0	60	44	0	0	12/15/2021
Regional Expansion	DCP Kinnickinnic	A.0001247.002	Kin Rbld 69 23 9kV Sub TAM DCP	0	0	0	0	0	0	12/15/2021
Reliability Requirement	Wissota Beach Sub Rebuild	A.0010173.006	BMN New 69 23 9kV Sub DCP	22	16	0	0	0	0	12/15/2020
Reliability Requirement	DCP Ironwood Substation	A.0010164.003	PKR 115 12.5kV SUB DCP	10	8	0	0	0	0	10/15/2020
Reliability Requirement	DCP Ironwood Substation	A.0010164.004	W3325 In Out at PKR SUB DCP	10	8	0	0	0	0	10/15/2020
Reliability Requirement	Clear Lake Area Sub DCP	A.0001186.002	Clear Lake Area Sub TAM	5	4	0	0	0	0	11/20/2020
Reliability Requirement	Clear Lake Area Sub DCP	A.0001186.008	Clear Lake Area Sub TAM Retire	2	2	0	0	0	0	6/30/2021
Reliability Requirement	Copperwood Mine	A.0001266.005	Copperwood Mine Eng Svc Agrment	0	0	0	0	0	0	6/1/2022
Reliability Requirement Total				**15,077**	**10,995**	**49,440**	**36,053**	**13,217**	**9,638**	
Interconnection	IA Tariff Fund	A.0000076.003	IA Tariff Fund NSPW	0	0	6,112	4,457	3,004	2,190	12/31/2024
Interconnection	SFNU MTEP18 NSPM	A.0001463.001	SFNU WI Pre Con	117	85	1,904	1,388	4,023	2,934	1/1/2026
Interconnection	DPC Arkansaw Tap Interconnection	A.0001177.001	W3415 Tap to DPC at Arkansaw Sub	1,241	905	0	0	0	0	3/30/2021
Interconnection	DPC Switch Interconnections	A.0000873.008	DPC W3408 Interconnection	0	0	244	178	0	0	3/15/2022
Interconnection	DPC Switch Interconnections	A.0000873.009	W3408 DPC N-5 Tie Nelson	244	178	0	0	0	0	9/15/2021
Interconnection	DPC Switch Interconnections	A.0000873.010	W3427 DPC N-4 Tie Clear Lake	234	171	0	0	0	0	12/31/2021
Interconnection	DPC Switch Interconnections	A.0000873.011	W3403 DPC Hanson Tap SW	266	194	0	0	0	0	4/30/2021
Interconnection Total				**2,102**	**1,533**	**8,259**	**6,023**	**7,027**	**5,124**	
Physical Security and Resiliency	Physical Security	A.0000710.002	NSPW Physical Security Sub Infrstruc	2,810	2,049	1,114	812	502	366	12/15/2024
Physical Security and Resiliency	Physical Security	A.0000710.006	NSPW Physical Security Comm	973	710	202	147	150	110	12/25/2025
Physical Security and Resiliency	Physical Security	A.0000710.024	La Crosse Physical Security Comm	759	554	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.025	Stone Lake Physical Security Comm	1,649	1,203	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.034	La Crosse Physical Security Infrastr	1,449	1,057	0	0	0	0	12/15/2021
Physical Security and Resiliency	Physical Security	A.0000710.035	Stone Lake Physical Security Infrastr	1,358	990	0	0	0	0	12/15/2021
Physical Security and Resiliency	OT Cyber Security NSPW	A.0001457.001	Monitoring Logging RTCA WI	0	0	819	597	485	353	10/31/2024
Physical Security and Resiliency	OT Cyber Security NSPW	A.0001457.002	Asset Management Software WI	0	0	272	198	332	242	12/31/2025
Physical Security and Resiliency	NSPW Geomagnetic Disturbances (GMD)	A.0000766.005	NSPW Geomagnetic Disturbance (GMD)	0	0	501	365	0	0	12/31/2022
Physical Security and Resiliency	NSPW Electro Mag Pulse (EMP)	A.0000775.005	NSPW Electro Mag Pulse (EMP)	0	0	158	115	0	0	12/31/2022
Physical Security and Resiliency Total				**9,000**	**6,563**	**3,066**	**2,236**	**1,469**	**1,071**	
n/a	n/a	n/a	n/a	0	0	0	0	0	0	n/a
Regional Expansion Total				**0**	**0**	**0**	**0**	**0**	**0**	
Communications Infrastructure	Comm Network Program	A.0001320.010	NSPW Comm Network Program Comm	5,024	3,663	5,025	3,664	9,931	7,242	12/15/2025
Communications Infrastructure	NSPW COMM Circuit Upgrades	A.0000487.001	NSPW 2017 COMM Circuit Upgrades	170	124	171	125	170	124	12/31/2025
Communications Infrastructure	AGIS FLISR	D.0001902.026	AGIS FLISR NSPW Transmission Precon	0	0	256	186	0	0	12/31/2022
Communications Infrastructure	Cedar Falls Relaying - COMM	A.0001481.001	Cedar Falls Relaying - COMM	1	1	0	0	0	0	12/15/2021
Communications Infrastructure	Spokesville Relaying - COMM	A.0001482.001	Spokesville Relaying - COMM	1	1	0	0	0	0	12/15/2021
Communications Infrastructure Total				**5,196**	**3,789**	**5,451**	**3,975**	**10,101**	**7,366**	
NSPW Total				**95,967**	**69,981**	**128,481**	**93,691**	**83,278**	**60,728**	

Transmission's O&M Costs by Category: 2017-2023
NSPM-Electric
($000,000)

Cost Category	2017 Actual	2018 Actual	2019 Actual	2017 – 2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Internal Labor	$21.40	$22.00	$20.40	$21.30	$20.00	$21.50	$22.10	$22.80
Contract Labor and Consulting	$4.70	$4.50	$4.50	$4.60	$3.90	$4.50	$4.50	$4.40
Employee Expenses	$2.70	$2.90	$2.70	$2.80	$2.30	$3.10	$3.10	$3.10
Fees	$3.50	$3.50	$3.40	$3.50	$3.50	$3.70	$3.90	$4.20
Materials	$3.60	$3.30	$2.50	$3.10	$1.70	$2.50	$2.40	$2.30
Other	$5.10	$4.10	$2.60	$3.90	$2.60	$2.90	$2.70	$3.60
Total	**$41.00**	**$40.30**	**$36.10**	**$39.20**	**$34.00**	**$38.20**	**$38.70**	**$40.40**

NSP System Transmission Expenses ($000's)

Description	2019 ACTUALS (000's)	2021 BUDGET (000's)	2022 BUDGET (000's)	2023 BUDGET (000's)
NSP JPZ payments and GRE JPZ charges	$ 60,404	$ 58,414	$ 60,066	$ 61,236
MISO Network Service	$ 7,761	$ 11,377	$ 11,896	$ 12,241
MISO Transmission Expansion Plan (RECB)	$ 131,177	$ 128,622	$ 129,969	$ 128,381
Schedule 2 (Reactive Supply)	$ 9,625	$ 11,512	$ 11,657	$ 11,649
MISO Schedules 10, 10-FERC	$ 11,392	$ 11,162	$ 11,866	$ 12,122
MISO Schedules 16 and 17	$ 8,569	$ 8,319	$ 8,033	$ 8,431
MISO Schedule 24	$ 1,222	$ 1,172	$ 1,208	$ 1,244
Schedule 1 (Sch, Sys Ctrl & Disp)	$ 234	$ 631	$ 660	$ 679
Sch 33 - Blackstart	$ 30	$ 30	$ 31	$ 32
Sch 45 - NREAC Recovery	$ 1	$ 2	$ 2	$ 2
Other native load deliveries	$ 73	$ 71	$ 71	$ 71
SPP Point-to-Point	$ 86	$ 75	$ 78	$ 80
MISO Point-to-Point	$ 80	$ 85	$ 88	$ 91
MISO System Studies	$ 80	$ 33	$ 34	$ 35
Self-Funded Network Upgrades	$ -	$ 4,145	$ 5,415	$ 5,415
Courtenay Wind Project - Point-to-Point and Interconnection Upgrades	$ 1,708	$ 1,708	$ 1,708	$ 1,708
Total Expense	**$ 232,443**	**$ 237,359**	**$ 242,783**	**$ 243,419**
Less:				
MISO Schedules 10, 10-FERC - Regional Markets portion	$ 254	$ 248	$ 266	$ 270
MISO Schedules 16 and 17	$ 8,569	$ 8,319	$ 8,033	$ 8,431
MISO Schedule 24	$ 1,222	$ 1,172	$ 1,208	$ 1,244
Note: Regional Markets Items [See Note #1]	**$ 10,045**	**$ 9,739**	**$ 9,507**	**$ 9,945**
MISO Transmission Expansion Plan (RECB)	$ 131,177	$ 128,622	$ 129,969	$ 128,381
Note: Items Collected through TCR	**$ 131,177**	**$ 128,622**	**$ 129,969**	**$ 128,381**
Blazing Star 2 Wind Project		$ 1,319	$ 2,589	$ 2,589
Blazing Star 1 Wind Project		$ 89	$ 89	$ 89
Border Winds		$ 336	$ 336	$ 336
Dakota Range 1 & 2 Wind Project		$ 1,078	$ 1,078	$ 1,078
Fox Tail Wind Farm		$ 891	$ 891	$ 891
Freeborn Wind Farm		$ 400	$ 400	$ 400
Courtenay Wind Project - Point-to-Point and Interconnection Upgrades	$ 1,708	$ 1,708	$ 1,708	$ 1,708
Note: Items Collected through RES	**$ 1,708**	**$ 5,822**	**$ 7,092**	**$ 7,092**
Net Base Rate Transmission Expense	**$ 89,513**	**$ 93,176**	**$ 96,215**	**$ 98,001**

Note #1
MISO energy and ancillary services market administration charges are reflected in Commercial Operations portion of Energy Supply budget and included in base rates.

NSP System Transmission Revenues ($000's)

Description	2019 ACTUALS (000's)	2021 BUDGET (000's)	2022 BUDGET (000's)	2023 BUDGET (000's)
Network JPZ - GRE/SMMPA/MRES	$ 56,936	$ 52,066	$ 55,598	$ 57,185
Network Service - Midwest ISO Tariff	$ 25,163	$ 30,595	$ 28,755	$ 29,618
MISO Transmission Expansion Plan (RECB)	$ 137,734	$ 131,068	$ 138,255	$ 136,928
Point-to-Point Firm, Point-to-Point Non Firm	$ 7,923	$ 6,353	$ 6,199	$ 6,205
Schedule 2 (Reactive Supply)	$ 8,592	$ 8,773	$ 8,773	$ 8,773
Tm-1 GFAs	$ -	$ -	$ -	$ -
Fixed GFA Contracts	$ 418	$ 423	$ 426	$ 427
Self-Funded Network Upgrades	$ -	$ 1,610	$ 4,710	$ 4,710
MISO Schedule 24 - Balancing Authority	$ 1,068	$ 1,170	$ 1,187	$ 1,223
Schedule 1 (Sch, Sys Ctrl & Disp)	$ 528	$ 544	$ 544	$ 544
GRE O&M service	$ 227	$ 226	$ 226	$ 226
Marshall TOPS Agreement	$ 137	$ 144	$ 148	$ 151
Total Revenue Collected	**$ 238,727**	**$ 232,970**	**$ 244,821**	**$ 245,991**
Less:				
Schedule 2 (Reactive Supply)	$ 8,592	$ 8,773	$ 8,773	$ 8,773
Note: Revenues transfer to Energy Supply	**$ 8,592**	**$ 8,773**	**$ 8,773**	**$ 8,773**
MISO Transmission Expansion Plan (RECB)	$ 137,734	$ 131,068	$ 138,255	$ 136,928
Note: Included as credit in TCR Rider	**$ 137,734**	**$ 131,068**	**$ 138,255**	**$ 136,928**
GRE O&M service	$ 227	$ 226	$ 226	$ 226
Marshall TOPS Agreement	$ 137	$ 144	$ 148	$ 151
Note: Revenues transfer to Distribution	**$ 364**	**$ 370**	**$ 373**	**$ 377**
Net Base Rate Transmisison Revenue	**$ 92,036**	**$ 92,760**	**$ 97,420**	**$ 99,913**

Joint Zonal Revenues and Expenses - 2021 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-21	$ 3,016,062	$ 483,368	$ 445,534	$ 3,944,965
Feb-21	$ 2,577,565	$ 441,503	$ 412,310	$ 3,431,378
Mar-21	$ 2,594,849	$ 459,649	$ 429,751	$ 3,484,248
Apr-21	$ 2,282,698	$ 411,408	$ 395,782	$ 3,089,888
May-21	$ 3,113,053	$ 537,518	$ 426,907	$ 4,077,477
Jun-21	$ 3,430,265	$ 611,635	$ 475,150	$ 4,517,050
Jul-21	$ 3,640,880	$ 696,868	$ 499,456	$ 4,837,203
Aug-21	$ 3,626,648	$ 630,240	$ 489,847	$ 4,746,735
Sep-21	$ 3,338,874	$ 599,751	$ 452,815	$ 4,391,440
Oct-21	$ 2,350,545	$ 494,875	$ 411,523	$ 3,256,943
Nov-21	$ 2,718,873	$ 447,305	$ 424,381	$ 3,590,559
Dec-21	$ 3,023,956	$ 477,603	$ 449,150	$ 3,950,709
Total	**$ 35,714,267**	**$ 6,291,722**	**$ 5,312,606**	**$ 47,318,595**

GRE JPZ	GRE
Jan-21	$ 396,792
Feb-21	$ 395,610
Mar-21	$ 325,530
Apr-21	$ 313,140
May-21	$ 353,980
Jun-21	$ 450,406
Jul-21	$ 498,938
Aug-21	$ 472,470
Sep-21	$ 435,950
Oct-21	$ 325,862
Nov-21	$ 371,380
Dec-21	$ 406,978
Total	**$ 4,747,037**

Total GRE Revenue **$ 40,461,303.84**

Total Transmission Joint Zonal Revenue **$52,065,632**

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-21	$ 2,657,372	$ 1,135,846	$ 101,198	$ 43,441	$ 97,603	$ 131,028	$ 150,813	$ 4,317,301
Feb-21	$ 2,356,955	$ 1,007,437	$ 89,757	$ 38,530	$ 86,569	$ 116,216	$ 133,764	$ 3,829,227
Mar-21	$ 2,390,118	$ 1,021,612	$ 91,020	$ 39,072	$ 87,787	$ 117,851	$ 135,646	$ 3,883,105
Apr-21	$ 2,118,678	$ 905,590	$ 80,683	$ 34,634	$ 77,817	$ 104,467	$ 120,241	$ 3,442,110
May-21	$ 2,606,411	$ 1,114,063	$ 99,257	$ 42,608	$ 95,731	$ 128,516	$ 147,921	$ 4,234,506
Jun-21	$ 3,339,109	$ 1,427,242	$ 127,159	$ 54,585	$ 122,643	$ 164,643	$ 189,504	$ 5,424,885
Jul-21	$ 3,841,385	$ 1,641,930	$ 146,287	$ 62,796	$ 141,091	$ 189,409	$ 218,009	$ 6,240,908
Aug-21	$ 3,669,984	$ 1,568,668	$ 139,760	$ 59,994	$ 134,795	$ 180,958	$ 208,282	$ 5,962,440
Sep-21	$ 3,118,733	$ 1,333,046	$ 118,767	$ 50,983	$ 114,548	$ 153,777	$ 176,997	$ 5,066,851
Oct-21	$ 2,421,863	$ 1,035,181	$ 92,229	$ 39,591	$ 88,953	$ 119,416	$ 137,447	$ 3,934,681
Nov-21	$ 2,408,054	$ 1,029,279	$ 91,703	$ 39,365	$ 88,446	$ 118,735	$ 136,664	$ 3,912,246
Dec-21	$ 2,726,640	$ 1,165,453	$ 103,835	$ 44,573	$ 100,147	$ 134,444	$ 154,744	$ 4,429,836
Total	**$ 33,655,301**	**$ 14,385,348**	**$ 1,281,655**	**$ 550,170**	**$ 1,236,131**	**$ 1,659,459**	**$ 1,910,031**	**$ 54,678,095**

GRE JPZ	GRE
Jan-21	$ 314,299
Feb-21	$ 275,049
Mar-21	$ 305,024
Apr-21	$ 262,982
May-21	$ 252,830
Jun-21	$ 315,831
Jul-21	$ 411,049
Aug-21	$ 364,851
Sep-21	$ 275,259
Oct-21	$ 296,954
Nov-21	$ 313,844
Dec-21	$ 347,867
Total	**$ 3,735,841**

Total GRE Expense **$ 37,391,142.03**

Total Transmission Joint Zonal Expense **$ 58,413,935** -

Net Transmission Joint Zonal **($6,348,303)**

Net Transmission Joint Zonal Payment for NSP Pricing Zone **$ (7,359,499)**
Net Transmission Joint Zonal Payment for GRE Pricing Zone **$ 1,011,196**

Joint Zonal Revenues and Expenses - 2022 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-22	$ 3,232,390	$ 518,038	$ 477,490	$ 4,227,918
Feb-22	$ 2,762,441	$ 473,170	$ 441,883	$ 3,677,494
Mar-22	$ 2,780,965	$ 492,617	$ 460,575	$ 3,734,157
Apr-22	$ 2,446,425	$ 440,916	$ 424,170	$ 3,311,511
May-22	$ 3,336,337	$ 576,071	$ 457,527	$ 4,369,935
Jun-22	$ 3,676,301	$ 655,505	$ 509,230	$ 4,841,036
Jul-22	$ 3,902,023	$ 746,851	$ 535,279	$ 5,184,153
Aug-22	$ 3,886,771	$ 675,444	$ 524,981	$ 5,087,196
Sep-22	$ 3,578,356	$ 642,769	$ 485,293	$ 4,706,417
Oct-22	$ 2,519,138	$ 530,370	$ 441,040	$ 3,490,548
Nov-22	$ 2,913,884	$ 479,388	$ 454,820	$ 3,848,092
Dec-22	$ 3,240,850	$ 511,859	$ 481,365	$ 4,234,074
Total	**$ 38,275,882**	**$ 6,742,998**	**$ 5,693,654**	**$ 50,712,534**

GRE JPZ	GRE
Jan-22	$ 408,379
Feb-22	$ 407,161
Mar-22	$ 334,978
Apr-22	$ 322,216
May-22	$ 364,282
Jun-22	$ 463,600
Jul-22	$ 513,589
Aug-22	$ 486,327
Sep-22	$ 448,711
Oct-22	$ 335,321
Nov-22	$ 382,204
Dec-22	$ 418,870
Total	**$ 4,885,639**

Total GRE Revenue **$ 43,161,520.39**

Total Transmission Joint Zonal Revenue **$55,598,172**

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-22	$ 2,778,929	$ 1,135,857	$ 101,179	$ 43,461	$ 97,591	$ 131,043	$ 150,798	$ 4,438,858
Feb-22	$ 2,464,769	$ 1,007,448	$ 89,741	$ 38,548	$ 86,558	$ 116,228	$ 133,750	$ 3,937,042
Mar-22	$ 2,499,449	$ 1,021,623	$ 91,004	$ 39,090	$ 87,776	$ 117,864	$ 135,632	$ 3,992,437
Apr-22	$ 2,215,592	$ 905,600	$ 80,669	$ 34,651	$ 77,807	$ 104,478	$ 120,229	$ 3,539,026
May-22	$ 2,725,636	$ 1,114,074	$ 99,239	$ 42,628	$ 95,719	$ 128,530	$ 147,906	$ 4,353,732
Jun-22	$ 3,491,850	$ 1,427,256	$ 127,137	$ 54,611	$ 122,627	$ 164,661	$ 189,484	$ 5,577,627
Jul-22	$ 4,017,102	$ 1,641,947	$ 146,261	$ 62,826	$ 141,073	$ 189,430	$ 217,987	$ 6,416,626
Aug-22	$ 3,837,860	$ 1,568,684	$ 139,735	$ 60,023	$ 134,778	$ 180,978	$ 208,261	$ 6,130,317
Sep-22	$ 3,261,394	$ 1,333,060	$ 118,746	$ 51,007	$ 114,534	$ 153,794	$ 176,979	$ 5,209,513
Oct-22	$ 2,532,647	$ 1,035,192	$ 92,212	$ 39,610	$ 88,942	$ 119,429	$ 137,433	$ 4,045,465
Nov-22	$ 2,518,206	$ 1,029,290	$ 91,687	$ 39,384	$ 88,435	$ 118,748	$ 136,650	$ 4,022,398
Dec-22	$ 2,851,365	$ 1,165,465	$ 103,817	$ 44,594	$ 100,134	$ 134,459	$ 154,729	$ 4,554,562
Total	**$ 35,194,798**	**$ 14,385,495**	**$ 1,281,426**	**$ 550,433**	**$ 1,235,973**	**$ 1,659,640**	**$ 1,909,837**	**$ 56,217,602**

GRE JPZ	GRE
Jan-22	$ 323,728
Feb-22	$ 283,301
Mar-22	$ 314,175
Apr-22	$ 270,871
May-22	$ 260,415
Jun-22	$ 325,306
Jul-22	$ 423,380
Aug-22	$ 375,797
Sep-22	$ 283,517
Oct-22	$ 305,863
Nov-22	$ 323,260
Dec-22	$ 358,303
Total	**$ 3,847,916**

Total GRE Expense **$ 39,042,713.77**

Total Transmission Joint Zonal Expense **$ 60,065,518**

Net Transmission Joint Zonal **($4,467,346)**

Net Transmission Joint Zonal Payment for NSP Pricing Zone **$ (5,505,069)**
Net Transmission Joint Zonal Payment for GRE Pricing Zone **$ 1,037,723**

Joint Zonal Revenues and Expenses - 2023 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-23	$ 3,324,458	$ 532,794	$ 491,091	$ 4,348,343
Feb-23	$ 2,841,125	$ 486,647	$ 454,469	$ 3,782,241
Mar-23	$ 2,860,176	$ 506,648	$ 473,694	$ 3,840,517
Apr-23	$ 2,516,107	$ 453,475	$ 436,251	$ 3,405,834
May-23	$ 3,431,367	$ 592,480	$ 470,559	$ 4,494,405
Jun-23	$ 3,781,014	$ 674,175	$ 523,735	$ 4,978,924
Jul-23	$ 4,013,165	$ 768,124	$ 550,526	$ 5,331,814
Aug-23	$ 3,997,478	$ 694,683	$ 539,934	$ 5,232,096
Sep-23	$ 3,680,279	$ 661,077	$ 499,116	$ 4,840,471
Oct-23	$ 2,590,891	$ 545,477	$ 453,602	$ 3,589,970
Nov-23	$ 2,996,881	$ 493,042	$ 467,775	$ 3,957,698
Dec-23	$ 3,333,160	$ 526,438	$ 495,076	$ 4,354,674
Total	**$ 39,366,100**	**$ 6,935,060**	**$ 5,855,828**	**$ 52,156,988**

GRE JPZ	GRE
Jan-23	$ 420,313
Feb-23	$ 419,059
Mar-23	$ 344,710
Apr-23	$ 331,565
May-23	$ 374,893
Jun-23	$ 477,191
Jul-23	$ 528,679
Aug-23	$ 500,599
Sep-23	$ 461,855
Oct-23	$ 345,063
Nov-23	$ 393,353
Dec-23	$ 431,119
Total	**$ 5,028,398**
Total GRE Revenue	**$ 44,394,498.76**

Total Transmission Joint Zonal Revenue **$ 57,185,386**

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-23	$ 2,862,280	$ 1,135,837	$ 101,183	$ 43,446	$ 97,594	$ 131,050	$ 150,792	$ 4,522,183
Feb-23	$ 2,538,698	$ 1,007,430	$ 89,744	$ 38,535	$ 86,561	$ 116,235	$ 133,745	$ 4,010,947
Mar-23	$ 2,574,418	$ 1,021,605	$ 91,007	$ 39,077	$ 87,778	$ 117,870	$ 135,627	$ 4,067,382
Apr-23	$ 2,282,047	$ 905,583	$ 80,671	$ 34,639	$ 77,810	$ 104,484	$ 120,224	$ 3,605,459
May-23	$ 2,807,389	$ 1,114,054	$ 99,243	$ 42,613	$ 95,722	$ 128,537	$ 147,901	$ 4,435,459
Jun-23	$ 3,596,585	$ 1,427,231	$ 127,141	$ 54,592	$ 122,631	$ 164,671	$ 189,478	$ 5,682,328
Jul-23	$ 4,137,592	$ 1,641,918	$ 146,266	$ 62,804	$ 141,077	$ 189,441	$ 217,979	$ 6,537,077
Aug-23	$ 3,952,973	$ 1,568,656	$ 139,740	$ 60,002	$ 134,782	$ 180,988	$ 208,253	$ 6,245,394
Sep-23	$ 3,359,217	$ 1,333,036	$ 118,750	$ 50,989	$ 114,537	$ 153,803	$ 176,972	$ 5,307,304
Oct-23	$ 2,608,611	$ 1,035,173	$ 92,216	$ 39,596	$ 88,944	$ 119,436	$ 137,429	$ 4,121,405
Nov-23	$ 2,593,737	$ 1,029,271	$ 91,690	$ 39,370	$ 88,437	$ 118,755	$ 136,645	$ 4,097,906
Dec-23	$ 2,936,889	$ 1,165,444	$ 103,820	$ 44,579	$ 100,137	$ 134,466	$ 154,723	$ 4,640,059
Total	**$ 36,250,438**	**$ 14,385,237**	**$ 1,281,471**	**$ 550,243**	**$ 1,236,010**	**$ 1,659,736**	**$ 1,909,769**	**$ 57,272,904**

GRE JPZ	GRE
Jan-23	$ 333,440
Feb-23	$ 291,800
Mar-23	$ 323,600
Apr-23	$ 278,997
May-23	$ 268,228
Jun-23	$ 335,065
Jul-23	$ 436,082
Aug-23	$ 387,071
Sep-23	$ 292,023
Oct-23	$ 315,039
Nov-23	$ 332,957
Dec-23	$ 369,052
Total	**$ 3,963,353**
Total GRE Expense	**$ 40,213,791.06**

Total Transmission Joint Zonal Expense **$ 61,236,257**

Net Transmission Joint Zonal **($4,050,871)**

Net Transmission Joint Zonal Payment for NSP Pricing Zone	**$ 52,156,988**
Net Transmission Joint Zonal Payment for GRE Pricing Zone	**$ 1,065,045**